

How
long can we
keep this up?

**ANNUAL GENERAL AND
SPECIAL MEETING**

You are cordially invited to attend the Annual General and Special Meeting of the Shareholders of Real Resources Inc., which will be held on May 4, 2006 at the Selkirk House Conference Centre on the second floor at 555 – 4th Avenue SW., Calgary, Alberta at 3:00 pm.

If unable to attend, shareholders are requested to complete and return the Proxy form to the Secretary of the Company.

**Real Resources Inc.
is a Calgary based
oil and gas company**

**active in the exploration, develop-
ment and production of crude oil
and natural gas in Western Canada.**

**The Company has grown through
exploration, development and
strategic acquisitions.**

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Just watch us.



2006		boe/d	_____
2005	10,394	boe/d	_____
2004	7,373	boe/d	_____
2003	5,491	boe/d	_____

What
did we
do for
you in
2005?

HIGHLIGHTS

FINANCIAL

(\$ thousands, except where noted)

	2005	2004	% change
Production revenue	215,271	108,103	99
Cash flow from operations*	133,415	56,173	138
Per share (basic)*	\$ 3.92	\$ 2.09	88
Per share (diluted)*	\$ 3.79	\$ 2.03	87
Net earnings	49,065	16,155	204
Per share (basic)	\$ 1.44	\$ 0.60	140
Per share (diluted)	\$ 1.40	\$ 0.58	141
Net debt	68,571	58,498	17
Total assets	529,681	279,656	89
Shareholders' equity	322,084	143,994	124
Net capital expenditures	269,167	90,311	198
Average common shares outstanding (thousands)	34,031	26,932	26

OPERATING

	2005	2004	% change
Working interest production			
Crude oil and liquids (bbls/d)	5,152	3,293	56
Natural gas (mcf/d)	31,451	24,478	28
Total oil equivalent (boe/d)	10,394	7,373	41
Average prices			
Oil (\$/bbl)	58.85	41.45	42
Natural gas (\$/mcf)	9.06	6.41	41
Cash flow netback (before abandonment) (\$/boe)	35.27	20.90	69
Operating costs (\$/boe)	7.25	7.42	(2)
General and administrative (\$/boe)	1.64	1.41	16
Wells drilled			
Gross	135	112	21
Net	109.9	86.1	28

We generated
total
production
growth of
41%

* Cash flow from operations, cash flow from operations per share and corporate netbacks are non-GAAP terms that represent net earnings adjusted for non-cash items on a boe and per share basis. The Company evaluates its performance based on these measures. The Company considers cash flow a key measure as it demonstrates the Company's ability to generate cash flow necessary to fund future growth through capital investment and to repay debt. The Company considers corporate netback a key measure as it demonstrates profitability relative to current commodity prices.

What's
different
from a
year
ago?



1 We have crossed the junior company threshold and are helping to lead a revival of the intermediate E&P class. Just look at our metrics. Average 2005 production topped 10,000 boe/d. Capital expenditures were \$269 million. Total year-end assets of \$530 million. Cash flow of \$133 million – nearly triple the previous year's.

2 Our deep Devonian program progressed from a concept to concrete reality with two major light oil discoveries. Our Virginia Hills 3-28 Nisku wildcat well tested at 1,400 bbls/d, one of Western Canada's most prolific oil discoveries of the year, and nearly equal to Real's entire production seven years ago.

3 We ramped up activity throughout our five core areas. Southeast Saskatchewan went from a few wells in 2004 to 22 wells in 2005, and today we have a medium-term inventory of nearly 400 locations. Gas exploration at McGregor Lake, Alberta has included 19 successful out of 21 total wells, growing production from zero on a two-section foothold to 6.5 mmcf/d on a burgeoning 80-section play.

4 Real exited 2005 with production of 12,200 boe/d, a year-over-year increase of nearly 50 percent. Early drilling results in 2006 have been encouraging and will lead to further significant production adds in Q2 of this year.

5 What's not different from a year ago is our ongoing commitment to the key principles of Real's growth strategy – proved over our eight years of growth.

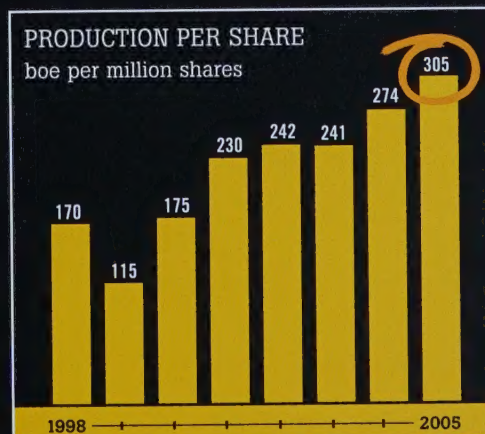
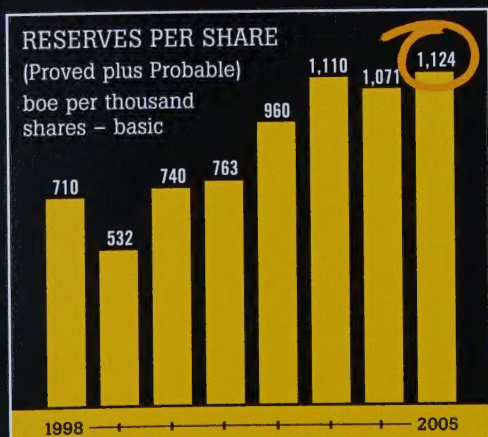
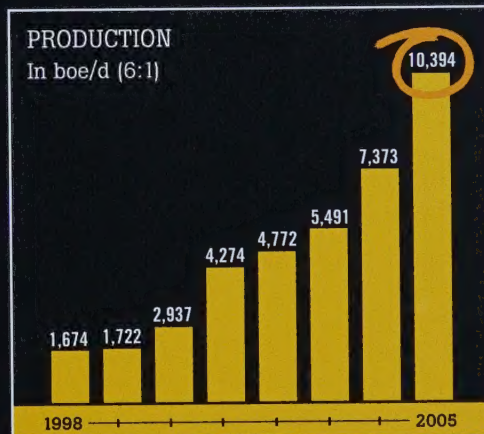
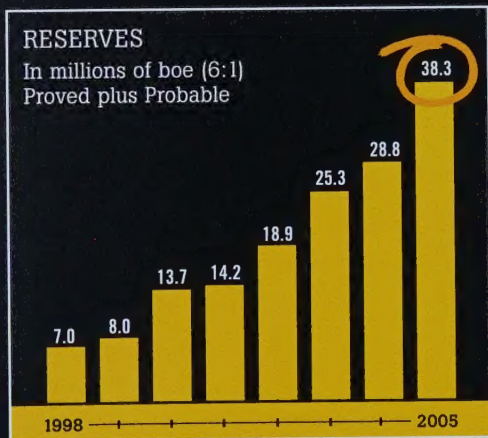
How
successful
is OUR
exploration
program?

In a word: very. Last year Real drilled 135 gross wells, up from 112 in 2004. Our success rate was 90 percent. We're very proud of that, especially because 35 percent of our wells were either rank wildcats or had a serious exploration component.

We had exploration successes all over. They were shallow, medium-depth and deep. From our two Ellerslie light oil discoveries at Ferrybank to our deep Devonian Nisku and Swan Hills oil discoveries, to pushing our McGregor Lake gas play far outward from the original pool.

Our drill bit successes added major reserves. Proved plus probable reserves at year end grew by 9.4 million boe, or 33 percent, year over year.

Reserves per share are back on track and were up by five percent. Our reserve life index now stands at 10.1 years. We are sustaining our exploration momentum with major new 100 percent proprietary 3-D seismic coverage and Crown land acquisitions. Going into 2006 Real has in excess of 1,000 drillable locations in its prospect inventory.



REAL Q&A

WITH LOWELL E. JACKSON, PRESIDENT AND C.E.O.

Q Overall, how was 2005 different from 2004?

✓A

The oil and natural gas business in Western Canada has changed dramatically, and Real has adapted to it. It's scenarios such as, how many more wells can we drill, where are we going to get the personnel, where will we get the services to make it happen, how long is the bull run in commodity prices going to last, and given all the outside pressures, how can we generate the same

level of return within a higher cost structure? Real is well prepared to deal with all of these pressures. We've retained superb people, we're attracting talented new people, and we've maintained our identity as a successful and growing explorer. I'm very happy with what we've accomplished. But can we do better? Absolutely. We will always strive to get better.

Q How were your results in 2005, and how did they mesh with your expectations?

✓A

Most of our individual results – cash flow, drilling success, debt ratio and others – were much better than expected. Our average netbacks were up by more than 50 percent year over year, and in the industry's top decile – probably in the top three companies. We take a conservative

approach in our planning, so that everything above meeting our minimum targets is upside. With our depth of inventory, we can ratchet things up based on drilling successes or improved industry parameters.

Q Was there any aspect that was much better or worse than planned?

✓A

Much better than expected was the very large 100 percent 3-D seismic program we shot in Virginia Hills for our deep Devonian oil exploration, followed by a massive Crown land acquisition. It's the type of program that you normally don't see a company of our size execute. But it's what

we were taught to do as individuals when we worked for the majors earlier in our careers. We are being true explorers, and that's a tremendous feeling. These moves set up years of activity over a large area with high-impact potential.

Q What were your biggest individual results or events of the year?

✓ A

The best result was the 3-28 well in Virginia Hills. It was our first successful deep Devonian well, drilled in late 2004, and it tested at a restricted rate of 1,400 bbls/d. That's about 30 times the rate of the typical new oil well in the Western Canada Sedimentary Basin. It came on production in 2005, when we released the confidential results. It overshadowed all kinds of other very good wells that were in the range of hundreds of barrels

or several million cubic feet per day. The other very big item was the Saskatchewan acquisition at Hastings, which opened up an industrial manufacturing-type drilling process with literally hundreds of low-risk locations that produce high-quality light oil. That one I just love. Part of it goes back to our willingness to take the risk, make the jump and invest the time.



Frank P. Muller
Vice President,
Exploration



Lowell E. Jackson
President & Chief
Executive Officer



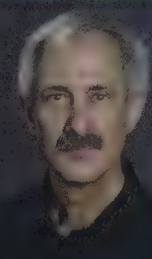
Rodger D. Trimble
Vice President,
Engineering



Pamela J. Orr
Vice President, Finance
& Chief Financial Officer



J. Dean Tucker
Vice President,
Operations



Michael J. Stone
Vice President, Land

Q Amid an inflationary industry environment, with many companies showing operating costs averaging around \$10/boe, how did you manage not only to control but to reduce average operating costs from \$7.42/boe in 2004 to \$7.25/boe in 2005?

✓A What it works out to is simply our longer term approach. We started in the lower risk part of the basin to establish cash flow. That allowed us to jump into the deeper part of the basin, which leads to the bigger prizes. The high volumes we're bringing on have more than compensated for the run-up in costs. We have put in our own processing

facilities, and we plan for pipelines and so on before we even drill an area. This allows us greater control over our costs rather than relying on others. If we continue to execute as we have, I believe we'll be able to hold the line on operating costs. It would be a stretch to reduce them further in the current environment.

Q What about capital efficiencies? Some analysts have voiced concerns about your average costs to bring on every new flowing boe of production.

✓A It's very tough to take one number and characterize an entire industry. I've never drilled a well on a single parameter such as dollars per flowing boe/d. But I've drilled a tremendous number of wells based on economics. Our objective is to maintain a recycle ratio of about two times, and the recycle ratio for 2005 activity is up substantially over 2004's. One reason is we've stayed with natural gas and light oil. We could achieve lower F&Ds and dollars per flowing boe by going after heavier crudes – but our recycle ratio would drop.

Other companies might sell their 3-D data to reduce their net capital spending – but we won't give up our competitive advantage. Another reason for the current numbers is that our exploration spending is very front end loaded – heavy on land, heavy on seismic, all of which is measured against this year's reserve additions. Many of our best exploration wells get virtually zero new reserves booked in the first year, which raises the apparent F&D cost. The reward is down the road.

Q You made an acquisition in 2005, something you hadn't done much of in the past few years. Why did you do this, and what did it accomplish?

✓A We look at acquisitions regularly, although we very rarely capture them. The main criteria are that the target has to involve a play type that we're doing already, and it must bring with it substantial upside potential to leverage our exploration skills. The Hastings property is synergistic to our production in southeast Saskatchewan,

where we have experience in Frobisher-Alida horizontal drilling. We levered that comfort into this \$44.7 million transaction. The property has a massive undrilled inventory: nearly 200 horizontal locations at traditional wellspacing plus a similar number taking advantage of Saskatchewan's new wellspacing rules.

Q Can you describe the significance of your asset mix and how that supports the Company's objectives?



A

Our asset portfolio sets us apart from our peers: we are the most diversified in geological depth and geography, and we're the best balanced in commodity mix. That's reflected in our overall economics. We've consciously stayed with light oil and natural gas because they are the higher netback commodities. Balancing natural gas with light oil creates an automatic price

hedge. Despite our growth in volumes, our inventory of drillable prospects is growing. We have everything from legacy, building-block, manufacturing-style shallow gas programs that pay our bills and generate cash flow, all the way to really big stuff where individual wells are equivalent to an entire emerging company.

Q Where does Real fit into the Canadian industry in terms of its size, its business model and its results?



A

We've gone into a unique sweet spot: we've crossed the magic 10,000 boe/d threshold. There are only a handful of companies that have done this in recent times. This handful is dispelling the myths that you can't do it, you'll stop growing. For investors, this is exciting because it's creating a new option,

something in between the large and the small capitalization companies. You get a measure of the stability of a larger company, but still the potential for double-digit growth. That was missing for a number of years in Canada.

Q Given the very high prices for acquiring assets and companies, do you detect a lengthening of the typical corporate cycle of formation, growth and monetization?



A

Yes I do. It's not going to be "5,000 boe/d and out" for as many companies anymore. But Real was always a long-term business model. And that is helping to shift the

perceptions of Real from an odd-duck company that had to justify its existence into a company that has the right business model for the market conditions.

Q What about the infrastructure and logistical challenges we're hearing so much about?

✓ A That question is asked continually. There is a problem, and we're doing everything that's humanly and legally possible to ensure we have the necessary services. We're not going the route of long-term contracts. But because of our large inventory, we can plan well ahead and schedule activity in our five core areas to guarantee extended work for contractors. We get companies and individuals working in an area, and keep

them working for a long time. Among the contractors, staff turnover is huge, but we've found many of their workers are looking for jobs that stay in one area for a while. Our approach creates personal stability for these workers, reducing turnover. Also, we pay our bills promptly. Creating conditions like these leaves us with happier contractors who want to work with us.

Q As a company grows, obviously the management team's abilities become more important. How deep is your bench strength, both at the senior level and in the middle technical ranks?

✓ A What's really helping are our exploration successes, our lengthening track record and our growing reputation as a company that challenges the technical minds of the industry's oil and gas finders and provides capital for explorers to pursue valid prospects. That means we're retaining our key experienced people, the proven performers. We're also getting great people

from some very large companies approaching us. That's adding to our bench strength. The huge size of our drilling inventory means there is a lot to do, and so we're also hiring energetic new technical graduates who are full of ideas and have potential for long and productive careers. So we're thinking ahead, planning, building and executing.

Q Were there important capital-related items in 2005?

✓ A Nothing company-altering. We raised some new equity for the Hastings purchase, and after the land purchase in West Central Alberta we raised equity to carry on the

program. Our balance sheet ended the year much stronger than a year earlier. We don't push our debt-to-cash-flow ratio in this frothy commodity price environment.

Q What is the reserves picture for 2005?

✓ A Reserves are up dramatically on an absolute basis – by one-third – and reflecting our new equity issues reserves per share are up by five percent. Despite our growing production, our reserve life index decreased only slightly year over year. In addition,

we've had tremendous discoveries in late 2004 and throughout 2005 in which we have not booked the upside. So with conservative bookings and active drilling, Real's reserves picture looks very bright going forward.

Q Is your strategy essentially the same as a year ago, or is it evolving?

✓A Our overall operating strategy remains. It's proven, it's working and we have a huge inventory of prospects to pursue. As a company, we are growing up. Our task will

be to operate efficiently at an increasing scale while maintaining our agile, exploration-oriented culture.

Q What are the main plans and objectives for 2006?

✓A The first is to begin unlocking the overall exploration potential that we've identified in West Central Alberta. The second is to execute on our very extensive shallow gas program. The third is to begin understanding what might be a sleeping giant, our potential in coalbed methane.

Meanwhile we'll continue to build our undeveloped land base and our seismic coverage. An exploration company is only as good as its inventory of drillable locations. In any given year, we are building for three years into the future.

Q What is your guidance for 2006?

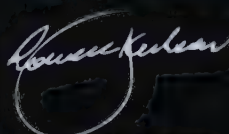
✓A As of this date, we are planning capital expenditures of \$250 million, which can move up with success. We are aiming for average production of 14,500 boe/d, which is higher than our minimum target of 15 percent per share growth. We're assuming average commodity prices of US\$45 WTI per bbl for oil, Cdn\$7.50 per mcf for natural gas,

and an exchange rate of US\$0.85 to Cdn\$1.00. At these parameters, we would generate cash flow of about \$125 million or \$3.35 per share. That is conservative – we know this – but it gives us comfort that we can execute fully on our program even if there is weakening in commodity prices.

Q Any closing thoughts?

✓A The thing I always feel so good about is how fortunate we've been to have patient, long-term shareholders. With supporters like these, how can we go wrong? I'd also like to thank our service providers. We've gone back to the same group year after year, and they continue to work with us,

and we're very grateful for these productive relationships. And I'm very excited that our growing base of employees includes not only senior people but very energetic, enthusiastic graduates who have long careers ahead of them and have chosen to be with Real.

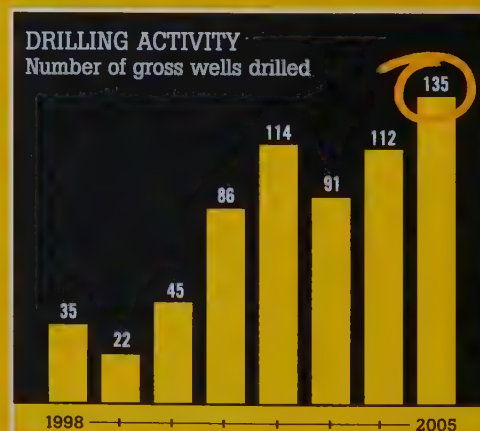
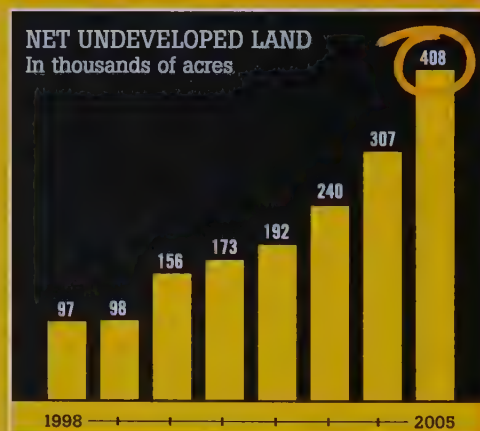
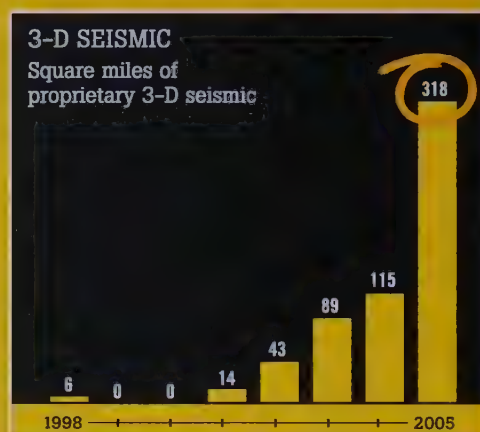


Lowell E. Jackson
President & Chief Executive Officer
March 15, 2006

How long can we keep this up?

For the foreseeable future. We are planning for longevity. The foundations to sustainable growth through the drill bit are continually building our base of undeveloped land, expanding our seismic coverage and interpretation, building our reserves and growing our inventory of drillable prospects. The graphs on these pages prove we're doing all of those.

The rest depends on sound execution. Real has a rolling activity blueprint stretching forward three years. Drilling large numbers of wells over several years improves success rates and reduces costs. We can book crucial field services well ahead of time, ensuring we deliver on plans. Including some lower rate but long-life pools in our drilling mix reduces our average annual production decline, sustaining growth by avoiding the "treadmill" effect. Despite spending record capital in 2005, our overall prospect inventory grew significantly. Despite doing more than ever last year – we have even more to do this year and next.



RISK

- GAS
- OIL

4-5 YEAR DRILLING
INVENTORY
[1000+ WELLS]

DEEP DEVONIAN REEFS

SHALLOW GAS &
CBM INITIATIVE

CONVENTIONAL OIL
& GAS EXPLORATION
AND DEVELOPMENT

LIGHT OIL
HORIZONTAL
DRILLING

REWARD

UNDEVELOPED
AND HOLDINGS



WEST CENTRAL
ALBERTA

Edmonton

CENTRAL
ALBERTA

EAST CENTRAL
ALBERTA

Calgary

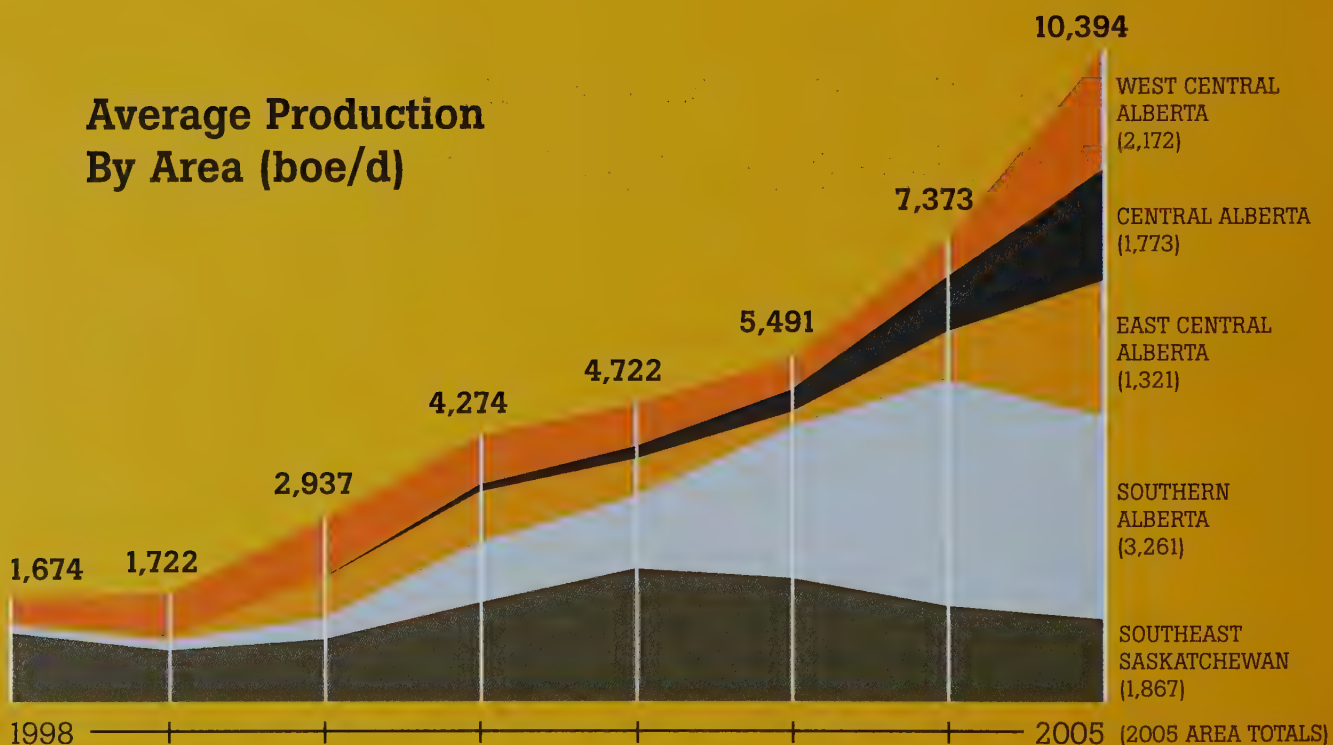
SOUTHERN ALBERTA

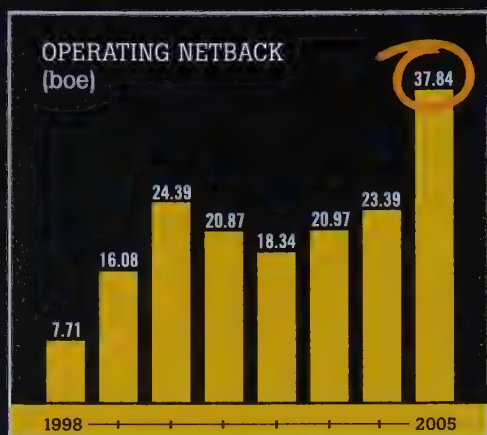
Regina

SOUTHEAST
SASKATCHEWAN

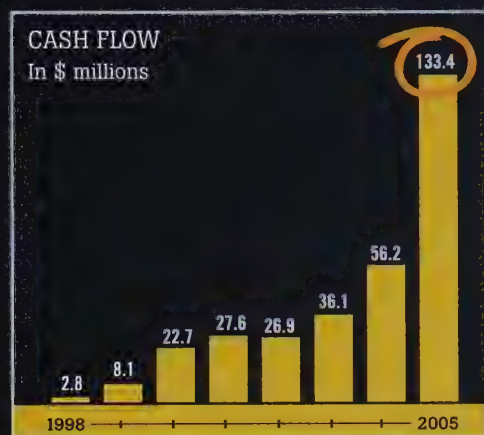
How are Real's assets performing?

**Average Production
By Area (boe/d)**

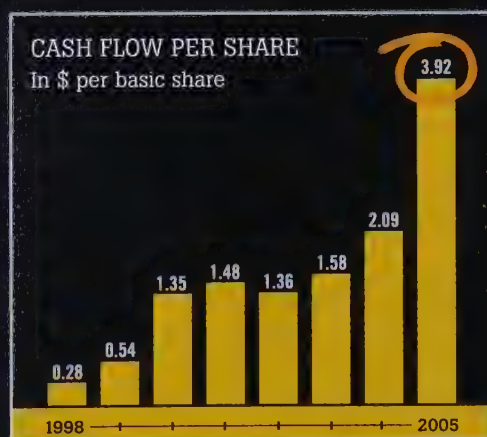




Real's 2005 operating netback of \$37.84 per boe was 62 percent higher than 2004. The increase reflects higher realized commodity prices and lower operating costs and royalty rates.



Cash flow from operations rose by 138 percent in 2005 compared to 2004 as a result of higher production and commodity prices. Average daily production was up 41 percent and the average 2005 cash flow netback was 69 percent higher.

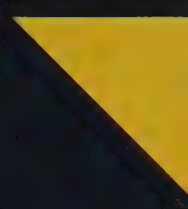


Cash flow per basic share was 88 percent higher than 2004 due to higher production levels and higher per unit netbacks. At the same time, there was only a 28 percent increase in the number of weighted common shares outstanding.



Real's 2005 closing share price was 110 percent higher than 2004 reflecting improved metrics in virtually all categories. Real had 37.3 million shares outstanding at year-end 2005.

Where's the
sizzle in
Real's
exploration
program?



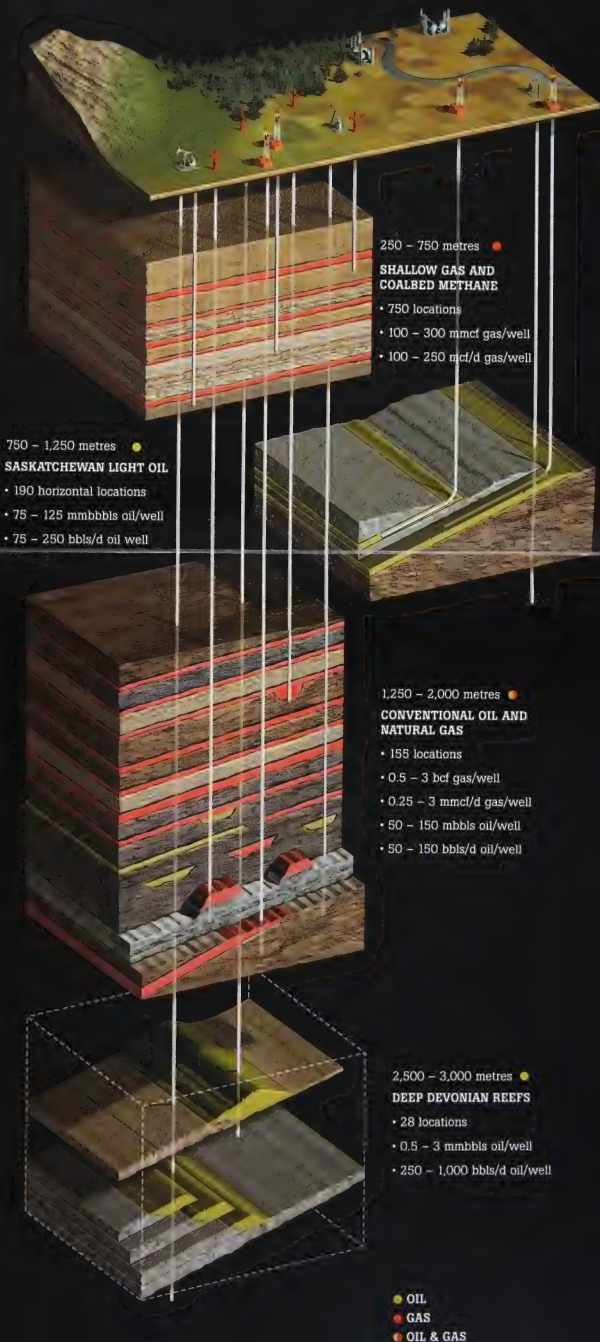
Everywhere, from east to west.

In our Saskatchewan revival we drove production from 200 bbls/d to 1,000 bbls/d – on just one half-section of land. At McGregor Lake we're 19 for 21 in our natural gas drilling – and our 80-section land base has only one well every three sections. Our deep Devonian exploration included some of western Canada's best new oil wells – and we've got undrilled geological anomalies racked up like bowling pins. With eight drilling rigs working the 2005-2006 winter season, Real's exploration team is sizzling.

Real's prospect portfolio

The simplified geological column below collects all prospective formations in Real's five core areas "under one roof". It shows that our portfolio of assets provides access to the full risk-reward spectrum of oil and natural gas geology. Shallow depth prospects hold low-risk, low-cost, lower-rate pools generating long-term cash flow. Our light oil, horizontal drilling projects in multiple medium-depth zones harbour conventional targets – the bread and butter of our development and exploration drilling. Deep prospects can hold company-making "home runs", where an individual well might produce as much as a whole junior exploration company.

When you invest in Real, you're not risking your capital on a single play type – you're buying a cross-section of the Western Canada Sedimentary Basin.



What's so
hot about
the
Deep
Devonian
in West Central
Alberta?

Big reserves. Big production.

Real's two major discoveries were drilled in a region unexplored for deep Devonian potential for the past 40 years, which legacy producers no longer considered prospective for large oil accumulations. We proved the opposite – and we're just getting started.

The first breakthrough was a Nisku wildcat at 2,500 metres. The 100 percent Real well tested at a restricted rate of 1,400 bbls/d plus 0.5 mmcf/d of natural gas, with back pressure of 700 psi. Drilled in late 2004, the 3-28 well's results were published in August 2005. It is currently on production at a restricted rate of 600 bbls/d, having already yielded reserves of over 140,000 bbls.

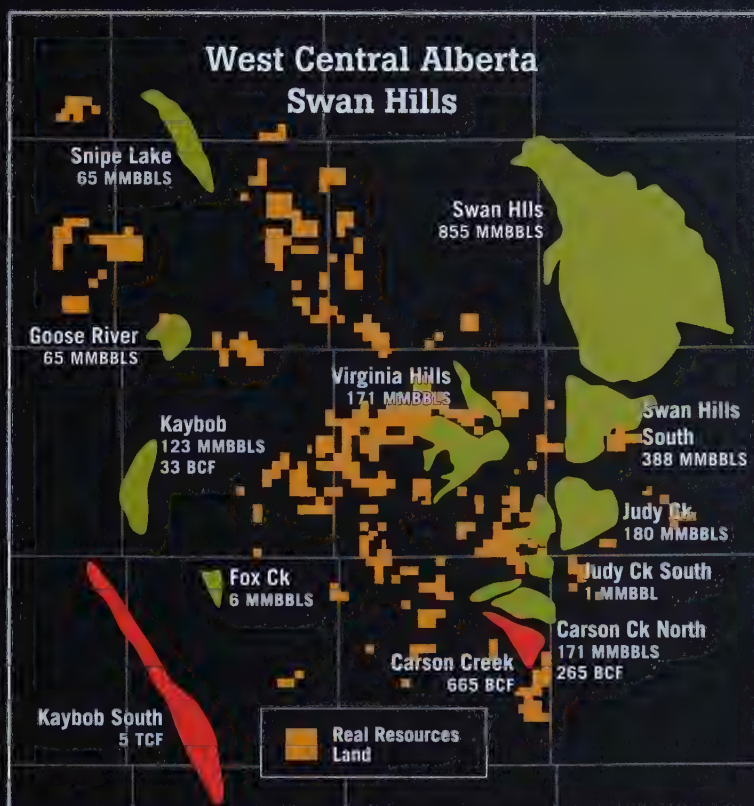
Our second discovery was a Swan Hills reef test at 3,000 metres. Testing at 1,000 bbls/d, the 13-7 well came on production in January 2005 at 350 bbls/d, restricted only by facility capacity.

What's the potential?

Huge. Alberta's historical Swan Hills reservoirs have produced a cumulative 2.3 billion barrels of oil and 6 trillion cubic feet of natural gas. In 2001 Real began re-evaluating a large, under-explored region west of several large Swan Hills and Nisku pools.

In 2005, following initial drilling success, the Company made a major commitment to deep Devonian exploration, commissioning 160 square miles of new, 100 percent proprietary 3-D seismic and a 100-township high-resolution aeromagnetic survey. Real has assembled a land base totalling over 350 sections at close to 95 percent working interest, including 125 sections acquired through Crown sales in the latter half of 2005.

Our 3-28 Nisku pool, now designated the Virginia Hills Nisku 'A' Pool, has oil-in-place estimated at 15 million barrels. Nisku reservoirs typically exhibit recovery factors of 30 percent on primary production and 65 percent on secondary production. Real has identified eight similar geological anomalies on their 100 percent proprietary 3-D seismic, all of which we intend to drill. This region is free of the landowner issues affecting Alberta's other major Nisku play area in West Pembina.



How are Real's
bread
and
butter
plays
advancing?

Conventional Oil and Natural Gas Development

SOUTHERN ALBERTA – Over the past 18 months Real's oil and natural gas production from the multiple medium-depth zones in this region has rebounded, moving from gentle decline under a moderate level of low-risk development activity back into a growth scenario. Real has leapfrogged out of its main Scandia and Enchant properties, which continue to produce natural gas from Mannville sands and oil from the Arcs formation but are nearing maturity.

Real's new exploration play at McGregor Lake lies in a lightly drilled area about 30 miles west of Scandia/Enchant, surrounded by successful production by competitors. After obtaining a toehold in 2004, Real began drilling on prospects defined by geology and 2D trade seismic data. With early success, Real in 2005 accelerated activities dramatically, expanding to 80 sections of lands and drilling 21 new wells, of which 19 are successful natural gas producers.

Wells at McGregor Lake typically come on production at 0.5 to 1.0 mmcf/d. Real's volumes climbed to 6.5 mmcf/d during 2005, justifying the construction of a new Company-owned processing facility. Further drilling success through year-end triggered a doubling of the plant's capacity, which was completed in February 2006. Real's extensive land base and the low drilling density of only one well every three sections creates major "running room" for this excellent play. The Company plans to drill a further six to eight wells per quarter throughout 2006.

CENTRAL ALBERTA – Real continues to generate growth from the medium-depth, multi-zone opportunities that remain in this highly competitive, established producing region of Alberta. Capital investment of \$33 million in 2005 funded 22 net wells, driving production from an average of 875 boe/d in 2004 to 1,773 boe/d in 2005.

At Ferrybank, one of Real's two main properties in this core area, the Company made two light oil discoveries in 2005. With established infrastructure, seismic coverage and a sizeable land position, Ferrybank continues to yield productive oil and condensate-rich natural gas wells, with typical reserves of 1-2 bcf or 100-200 mbbls per successful well. A \$21 million acquisition in November 2005 added 15 sections of land and 350 bbls/d of production, creating a more coherently organized property and providing new drilling prospects.

At Crystal, the other significant area property, Real is developing a resource-type play. Such wells typically flow at 0.5 to 1.0 mmcf/d, offering long reserve life and low risk on a density of two wells per section. The Company intends to drill six to eight wells per quarter in Central Alberta over the next 18 months.

WEST CENTRAL ALBERTA – Even if it weren't the scene of Real's deep Devonian discoveries, discussed in the previous pages, West Central Alberta would be the Company's foremost exploration area. Numerous zones from 500 to 2,000 metres are prospective for oil and/or natural gas, including the Dunvegan, Viking, Notikewin, Wilrich, Gething, Jurassic and Montney sands.

At an average cost of \$1 million per well, this is a high-impact area. Real's expanded 2005 program in West Central Alberta included 22 net wells and accounted for one-third of overall capital spending. Average production grew from 780 boe/d in 2004 to 2,172 boe/d in 2005.

Real's success in this technically complex area was enhanced by a conceptual shift, in which one-off drilling was eliminated in favour of minimum two- to four-well programs. This reduced statistical risks and improved capital efficiencies. In addition, before drilling, Real surveys and licenses all prospective drilling areas for pipeline access, reducing tie-in times on new wells.

Successes in 2005 occurred throughout the core area. Seven of nine wells drilled as a resource play at Judy Creek are successful new natural gas producers. At Windfall, Real added production from three zones. At Sturgeon Lake, two prospects identified on 3-D seismic were drilled and completed as multi-zone natural gas producers.

As of mid-March 2006, the results of Real's 2006 winter drilling program in West Central Alberta have contributed to a record quarter. Downspace drilling at Judy Creek has been successful. Three new wells at Two Creeks have been some of Real's best ever, production testing at 4-5 mmcf/d each. Numerous other wells have been tested at 0.5-1 mmcf/d. Real's 160 square mile, 100 percent proprietary 3-D seismic program, the first shot in this large, under-drilled area of Alberta, has revealed numerous opportunities for future drilling.

Saskatchewan Light Oil Development

Real's Southeast Saskatchewan revival drove the largest production volume growth of the Company's five core areas in 2005. The key has been a new regulation permitting downspacing of horizontal Alida-Frobisher wells to 75-metre intervals. On just one half-section of land at Alida-West, Real's downspace drilling in 2005 increased production of high-netback light oil from 200 bbls/d to a peak of 1,000 bbls/d. Combined activity in the core area included capital investment of \$30 million to drill 26 wells, raising average production from 564 boe/d in 2004 to 1,867 boe/d in 2005, well above target.

Significant further growth potential came with the \$44.7 million acquisition in April 2005 of a small private producer at Hastings. The acquired property covers five sections producing Alida-Frobisher oil. Mapping indicates resources of 43 million barrels of oil-in-place, with current cumulative recovery of less than five percent. Real plans a systematic multi-year harvesting program, including 190 horizontal wells at 150-metre intervals, followed over the longer term by an equal number at 75-metre spacing.

Real anticipates increasing the recovery factor at Hastings to 30 percent of the oil-in-place. Despite its high-impact potential, it is a low-risk play. Drilling success rates on horizontal Alida-Frobisher wells are virtually 100 percent, typically coming on production at 80 bbls/d and yielding reserves of about 65,000 bbls over ten years.

Shallow Gas

Driven by favourable economics at current commodity prices, Real's shallow gas program is an engine of production growth. It has three main components: conventional low-rate wells from very shallow depths at Atlee-Buffalo and Bindloss; a resource play focused on long-life Viking gas at West Provost; and early-stage evaluation of dry coalbed methane (CBM) potential underlying much of Real's Southern and Central Alberta lands. For 2006 Real has allocated approximately \$40 million to drill up to 125 shallow gas wells, targeting production to increase from 3 mmcf/d at year-end 2005 to 7 mmcf/d at year-end 2006.

ATLEE-BUFFALO/BINDLOSS (SOUTHERN ALBERTA) – These low-risk Medicine Hat and Milk River formation pools typically have a reserve life index of 40 years, creating stable production from very low-rate wells. Real is increasing activity from four wells drilled in 2005 to a planned 30 in 2006, focused on downspacing well densities on its large contiguous land blocks.

WEST PROVOST VIKING GAS UNIT (EAST CENTRAL ALBERTA) – With a 48 percent average working interest and operatorship of facilities over this extensive area, Real is able to systematically develop the low-risk, long-life Viking gas sands. Capital efficiencies are improved by batch drilling wells using coiled tubing units. Eighteen wells drilled in 2005 yielded very good results, production testing at the 100-500 mcf/d range typical for the Viking. This play will continue for years, as Real's 175-section land base has not yet reached an average density of one well per section, versus potential to drill up to four wells per section. Real plans to drill 40 new Viking gas wells at West Provost in 2006.

CBM (SOUTHERN AND CENTRAL ALBERTA) – Real has two areas prospective for participation in Alberta's burgeoning shallow, dry CBM play. The Ferrybank property of Central Alberta includes 30 sections of land with dry Horseshoe Canyon coals, and Real is contemplating drilling 15-20 CBM wells in 2006. In Southern Alberta, Real in 2005 drilled its first CBM well, an exploration test of the Belly River coals. In this core area, the Company holds 125 sections of land prospective for shallow, dry, gas-bearing coals. These CBM wells typically produce at 50-100 mcf/d, requiring a high volume of drilling to attain meaningful production volume. Further drilling will be undertaken in 2006 to evaluate CBM potential in Central Alberta.

Operations and Statistical Review

STATISTICAL REVIEW

RESERVES RECONCILIATION – FORECAST PRICES AND COSTS ^{(1) (2)}

Reconciliation of Company Gross Reserves by Principal Product Type

	Light and Medium Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	Total (mboe)
Total proved				
Opening balance	8,745	69,540	696	21,031
Discovery	124	13,646	280	2,678
Extension	855	7,917	155	2,330
Improved recovery	1,349	4,078	23	2,052
Revisions	548	(3,022)	247	291
Acquisitions	1,506	2,778	56	2,025
Dispositions	-	-	-	-
Production	(1,645)	(11,479)	(235)	(3,793)
Closing balance	11,482	83,459	1,222	26,614
Probable				
Opening balance	3,890	21,933	266	7,812
Discovery	121	7,855	114	1,545
Extension	(98)	10,275	136	1,750
Improved recovery	262	6,147	109	1,395
Revisions	(973)	(4,805)	(39)	(1,813)
Acquisitions	709	1,349	24	958
Dispositions	-	-	-	-
Production	-	-	-	-
Closing balance	3,911	42,754	610	11,647
Proved plus probable				
Opening balance	12,635	91,473	962	28,843
Discovery	245	21,501	394	4,223
Extension	757	18,192	291	4,080
Improved recovery	1,611	10,225	132	3,447
Revisions	(425)	(7,827)	208	(1,522)
Acquisitions	2,215	4,127	80	2,983
Dispositions	-	-	-	-
Production	(1,645)	(11,479)	(235)	(3,793)
Closing balance	15,393	126,213	1,832	38,261

(1) May not add due to rounding.

(2) Gross reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.

RESERVES BY PROPERTY ^{(1) (2)}

(at December 31, 2005)

	Light and Medium Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	Total (mboe)
Total proved				
Ferrybank	1,137	9,233	341	3,017
Hays/Enchant	2,688	2,848	127	3,290
Pageant/McGregor	-	14,505	135	2,553
Carnduff	2,230	1,559	-	2,490
West Provost	204	12,427	35	2,310
Scandia	232	9,657	121	1,963
Atlee-Buffalo	-	12,028	-	2,005
Virginia Hills	1,011	561	18	1,123
Judy Creek	-	4,184	54	751
Crystal	-	3,261	155	699
Alida West	837	357	-	896
Sturgeon Lake	-	2,150	147	505
Rocanville/Welwyn	694	-	-	694
Sounding Lake	683	104	3	703
Sakwatamau	507	609	5	613
Neutral Hills	461	426	1	533
Consort	429	42	1	437
Other properties	369	9,508	79	2,032
Total	11,482	83,459	1,222	26,614
Probable				
Ferrybank	356	6,581	169	1,622
Hays/Enchant	848	754	36	1,010
Pageant/McGregor	38	7,369	75	1,341
Carnduff	846	616	-	948
West Provost	42	5,026	14	894
Scandia	238	3,085	29	781
Atlee-Buffalo	-	3,613	-	602
Virginia Hills	521	1,702	34	839
Judy Creek	18	3,011	22	542
Crystal	-	2,733	120	575
Alida West	195	83	-	209
Sturgeon Lake	-	1,918	70	390
Rocanville/Welwyn	195	-	-	195
Sounding Lake	167	26	1	172
Sakwatamau	114	135	1	138
Neutral Hills	95	38	-	101
Consort	112	10	-	114
Other properties	126	6,054	39	1,174
Total	3,911	42,754	610	11,647

RESERVES BY PROPERTY (CONTINUED) ^{(1) (2)}

	Light and Medium Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	Total (mboe)
Proved plus probable				
Ferrybank	1,493	15,814	510	4,639
Hays/Enchant	3,536	3,602	163	4,300
Pageant/McGregor	38	21,874	210	3,894
Carnduff	3,076	2,175	-	3,438
West Provost	246	17,453	49	3,204
Scandia	470	12,742	150	2,744
Atlee-Buffalo	-	15,641	-	2,607
Virginia Hills	1,532	2,263	52	1,961
Judy Creek	18	7,195	76	1,293
Crystal	-	5,994	275	1,274
Alida West	1,032	440	-	1,105
Sturgeon Lake	-	4,068	217	895
Rocanville/Welwyn	889	-	-	889
Sounding Lake	850	130	4	875
Sakwatamau	621	744	6	751
Neutral Hills	556	464	1	634
Consort	541	52	1	551
Other properties	495	15,562	118	3,207
Total	15,393	126,213	1,832	38,261

(1) May not add due to rounding.

(2) Gross Reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.

SUMMARY OF OIL AND GAS RESERVES – FORECAST PRICES AND COSTS ^{(1) (2)}

	Light and Medium Crude Oil (mbbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)	2005 Total boe (mboe)	2004 Total boe (mboe)
Proved					
Developed producing	9,645	65,826	1,061	21,677	17,387
Developed non-producing	97	6,879	79	1,323	1,222
Undeveloped	1,740	10,754	82	3,614	2,422
Total proved	11,482	83,459	1,222	26,614	21,031
Probable	3,911	42,754	610	11,647	7,812
Total proved plus probable	15,393	126,213	1,832	38,261	28,843

(1) May not add due to rounding.

(2) Gross Reserves represent the Company's interest before deducting royalties and without including any royalty interest of the Company.

NET PRESENT VALUE OF RESERVES – FORECAST PRICES AND COSTS ^{(1) (2)}

(including ARTC and before income taxes)

(\$ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved					
Developed producing	613,583	505,915	436,949	388,679	352,670
Developed non-producing	29,300	24,390	20,880	18,255	16,222
Undeveloped	70,224	45,545	32,134	23,707	17,904
Total proved	713,106	575,850	489,963	430,641	386,795
Probable	281,828	187,148	137,376	107,065	86,730
Total proved plus probable	994,935	762,998	627,338	537,706	473,525

(1) May not add due to rounding.

(2) As required by NI 51-101, undiscounted well abandonment costs of \$19.3 million for total proved reserves and \$24.1 million for total proved plus probable reserves are included in the Net Present Value determination.

PRICING FORECAST ⁽¹⁾

	West Texas Intermediate \$US/bbl			Edmonton Reference Price \$Cdn/bbl			Natural Gas Price AECO "C" \$Cdn/mcf		
December 31	2005	2004	2003	2005	2004	2003	2005	2004	2003
2004	-	-	29.00	-	-	37.61	-	-	6.00
2005	-	42.00	26.50	-	50.22	34.25	-	6.78	5.31
2006	60.00	40.00	25.50	69.57	47.76	32.90	10.54	6.52	4.83
2007	57.50	37.50	25.00	66.61	44.69	32.21	9.52	6.26	4.87
2008	55.00	35.00	25.50	63.64	41.62	32.85	8.32	6.00	4.92
2009	52.50	33.00	26.01	60.68	39.16	33.51	7.71	5.73	4.96
2010	50.00	33.50	26.53	57.72	39.75	34.18	7.10	5.85	5.01
2011	47.50	34.00	27.06	54.76	40.34	34.86	7.24	5.96	5.05
2012	48.45	34.50	27.60	55.85	40.92	35.56	7.39	6.08	5.15
2013	49.42	35.00	28.15	56.97	41.51	36.27	7.53	6.21	5.26
2014	50.41	35.50	28.72	58.11	42.10	37.00	7.68	6.33	5.36
Thereafter (per year)	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%

(1) Utilizing Paddock Lindstrom & Associates Ltd. January 1, 2006 price forecast.

NET PRESENT VALUE OF RESERVES – CONSTANT PRICES AND COSTS ^{(1) (2)}

(including ARTC and before income taxes)

(\$ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved					
Developed producing	742,370	588,891	494,444	430,291	383,613
Developed non-producing	39,037	31,188	25,820	21,949	19,040
Undeveloped	96,688	61,819	43,225	31,766	24,014
Total proved	878,095	681,898	563,489	484,006	426,667
Probable	371,360	242,878	175,854	135,275	108,242
Total proved plus probable	1,249,455	924,776	739,343	619,281	534,909

(1) May not add due to rounding.

(2) Price assumptions: \$68.05 Cdn\$/bbl Edmonton Reference Price and \$9.98 Cdn\$/mcf AECO "C" price.

PRODUCTION BY AREA

	Crude oil and NGL (bbls/d)		
	2005	2004	2003
Alida	850	307	222
Hays/Enchant	768	870	971
Ferrybank	619	204	80
Carnduff	616	-	-
Virginia Hills	377	24	-
Neutral Hills	328	415	719
Consort	249	357	444
Sounding Lake	247	297	350
Sakwatamau	190	3	-
Rocanville	159	155	147
West Provost	127	86	92
Westerose	57	93	47
Minor properties	565	482	280
Total	5,152	3,293	3,352
	Natural gas (mcf/d)		
	2005	2004	2003
Scandia	6,630	12,225	4,725
Ferrybank	4,704	1,959	691
Pageant/McGregor	3,866	-	-
Judy Creek	2,613	932	-
Virginia Hills	2,496	-	-
Atlee-Buffalo	1,630	1,669	1,879
West Provost	1,616	1,393	1,587
Sturgeon Lake	1,156	50	-
Crystal	917	217	-
Hays/Enchant	808	717	966
Stump	806	253	-
Westerose	721	1,251	671
Carnduff	702	-	-
Ricinus	690	1,159	904
Windfall	518	1,221	-
Minor properties	1,578	1,432	1,410
Total	31,451	24,478	12,833

ACREAGE SUMMARY

(acres)	Gross	Total	Net	Gross	Undeveloped	Net	Fair Market Value*
Alberta	665,135		513,596	470,055		386,282	\$ 65,498,090
Saskatchewan	28,239		26,574	22,227		21,587	\$ 2,924,196
Total	693,374		540,170	492,282		407,869	\$ 68,422,286

* Seaton - Jordan & Associates Ltd. - Undeveloped Lands only

DRILLING ACTIVITY

	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells						
Oil	5	5.0	6	5.3	4	4.0
Gas	33	26.1	22	18.1	14	11.8
Service	1	1.0	-	-	-	-
Dry	9	8.1	8	7.5	12	11.2
Subtotal	48	40.2	36	30.9	30	27.0
Success rate (%)	81	80	78	76	60	59
Average working interest (%)	-	84	-	86	-	90
Operated wells	40	-	33	-	27	-

Development wells

Oil	37	34.5	29	22.6	29	27.4
Gas	45	30.3	40	26.2	27	18.7
Service	2	2.0	-	-	-	-
Dry	3	3.0	7	6.4	5	5.0
Subtotal	87	69.8	76	55.2	61	51.1
Success rate (%)	97	96	91	88	92	90
Average working interest (%)	-	80	-	73	-	84
Operated wells	80	-	64	-	49	-

Total wells

Oil	42	39.5	35	27.9	33	31.4
Gas	78	56.3	62	44.3	41	30.5
Service	3	3.0	-	-	-	-
Dry	12	11.1	15	13.9	17	16.2
Total	135	109.9	112	86.1	91	78.1
Success rate (%)	91	90	87	84	81	79
Average working interest (%)	-	81	-	77	-	86
Operated wells	120	-	97	-	76	-

FINDING AND ON-STREAM COSTS ⁽¹⁾

	2005	2004	2003	2002 ⁽²⁾	2001 ⁽²⁾
Finding costs (\$ thousands)					
Land	35,629	13,378	9,143	4,408	3,170
Seismic	31,535	5,635	5,159	3,270	1,883
Drilling and completion	99,737	50,545	31,885	25,386	19,558
Acquisitions/dispositions (net)	68,466	(309)	(104)	13,087	2,331
Total finding costs	235,367	69,249	46,083	46,151	26,942
Facilities	33,800	21,062	13,416	8,119	7,768
Total on-stream costs	269,167	90,311	59,499	54,270	34,710
Reserve additions (mboe) (including acquisitions, dispositions and revisions)					
Proved	9,376	4,909	5,016	5,761	1,820
Proved plus probable	13,211	6,238	8,384	6,481	2,077
Finding cost per unit (\$/boe)					
Proved	25.10	14.10	9.19	8.01	14.80
Proved plus probable	17.82	11.10	5.50	7.12	12.97
On-stream (\$/boe)					
Proved	28.71	18.39	11.86	9.42	19.07
Proved plus probable	20.37	14.48	7.10	8.37	16.71
Operating netback (\$/boe)	37.84	23.39	20.97	18.34	20.87
Recycle ratio					
Proved	1.32	1.27	1.77	1.95	1.09
Proved plus probable	1.86	1.62	2.95	2.19	1.25

(1) Excludes the net increase (decrease) in future development costs on proved reserves of \$19.9 million, (\$1.3) million, \$8.5 million, (\$1.1) million, and \$4.2 million in 2005, 2004, 2003, 2002, and 2001 respectively; on proved plus probable reserves of \$48.4 million, \$3.0 million, \$10.8 million, (\$0.5) million, and \$4.4 million in 2005, 2004, 2003, 2002, and 2001 respectively.

(2) Represents proved plus 50 percent risked probable reserves.

	2005	3-year Average	5-year Average
Finding costs (\$ thousands)			
Land	35,629	19,383	13,146
Seismic	31,535	14,110	9,496
Drilling and completion	99,737	60,722	45,422
Acquisitions (net)	68,466	22,684	16,694
Total finding costs	235,367	116,900	84,758
Facilities	33,800	22,759	16,833
Total on-stream costs	269,167	139,659	101,591
Reserve additions (mboe)(including acquisitions, dispositions and revisions)			
Proved	9,376	6,434	5,377
Proved plus probable	13,211	9,278	7,279
Finding cost per unit (\$/boe)			
Proved	25.10	18.17	15.76
Proved plus probable	17.82	12.60	11.64
On-stream (\$/boe)			
Proved	28.71	21.71	18.90
Proved plus probable	20.37	15.06	13.96
Operating netback (\$/boe)	37.84	27.40	24.28
Recycle ratio			
Proved	1.32	1.26	1.28
Proved plus probable	1.86	1.82	1.74

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FINDING AND DEVELOPMENT COSTS (F&D)

AND FINDING, DEVELOPMENT AND NET ACQUISITIONS COSTS (FD&A) ⁽¹⁾

Year ended December 31, 2005	Capital Expenditures (\$'000s)	Total Proved Reserve Additions (mboe)	Total Proved Cost (\$/boe)	Total Proved plus Probable Reserve Additions (mboe)	Total Proved plus Probable Cost (\$/boe)
F&D exploration and development program before revisions	200,701	7,060	28.43	11,750	17.08
F&D exploration and development program after revisions (a)	200,701	7,351	27.30	10,228	19.62
Change in total proved future development capital (b)	19,924	n/a	n/a	n/a	n/a
Change in total proved plus probable future development capital (c)	48,434	n/a	n/a	n/a	n/a
Total proved F&D including change in future development (d) equals (a+b)	220,625	7,351	30.01	n/a	n/a
Total proved plus probable F&D including change in future development capital (e) equals (a+c)	249,135	n/a	n/a	10,228	24.36
Net acquisition/disposition activity (f)	68,466	2,025	33.81	2,983	22.95
Total 2005 FD&A costs before future development costs (a+f)	269,167	9,376	28.71	13,211	20.37
Total 2005 proved FD&A costs including future development costs (d+f)	289,091	9,376	30.83	n/a	n/a
Total 2005 proved plus probable FD&A costs including future development costs (e+f)	317,601	n/a	n/a	13,211	24.04

(1) The aggregate of the exploration and development costs incurred in 2005 and the change in 2005 in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for 2005.

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RESERVE LIFE INDEX

The Company's reserve life index using annualized fourth quarter production is 6.2 years for proved boe reserves compared to 6.9 years in 2004 and 8.9 years for proved plus probable boe reserves compared to 9.5 years in 2004. Reserve life calculated using annualized fourth quarter production may be more reflective of reserve life due to the active capital program and the level of new production added during the fourth quarter.

	2005	2005	2004	2004	2003	2003
	Using Annualized Q4 Production	Using Average Production	Using Annualized Q4 Production	Using Average Production	Using Annualized Q4 Production	Using Average Production
Production (mboe)	4,313	3,793	3,046	2,699	2,420	2,004
Proved reserves (mboe)	26,614	26,614	21,031	21,031	18,820	18,820
Proved reserve life index (years)	6.2	7.0	6.9	7.8	7.8	9.4
Proved plus probable reserves (mboe)	38,261	38,261	28,843	28,843	25,303	25,303
Proved plus probable reserve life index (years)	8.9	10.1	9.5	10.7	10.5	12.6

Report of Management and Directors on Oil and Gas Reserves Disclosure ⁽¹⁾

Management of Real Resources Inc. (the Company) is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

- (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and
- (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and
- (ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserve data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with the Annual Information Form.

The Reserves Audit Committee of the Board of Directors of the Company has:

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluators.

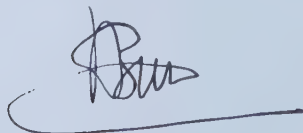
The Reserves Audit Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Audit Committee, approved:

- (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.



D. Nolan Blades, P. Eng
DIRECTOR



Frans Burger
DIRECTOR

Calgary, Alberta, Canada
February 23, 2006

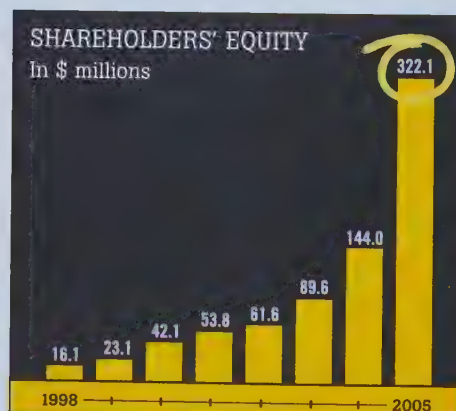
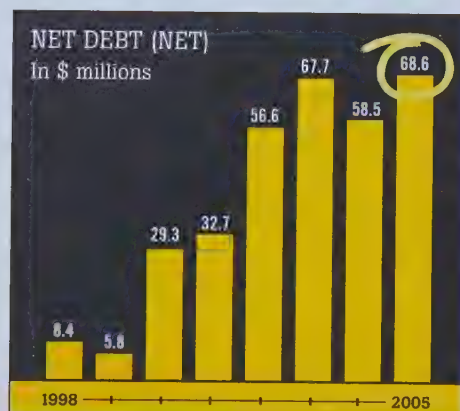
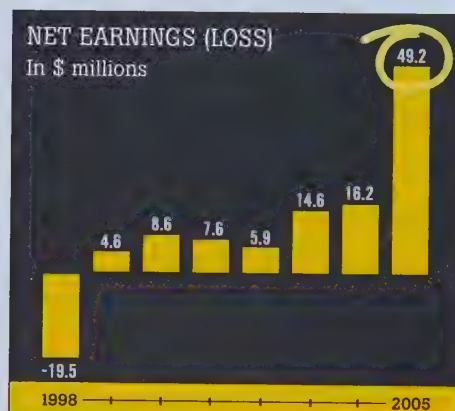
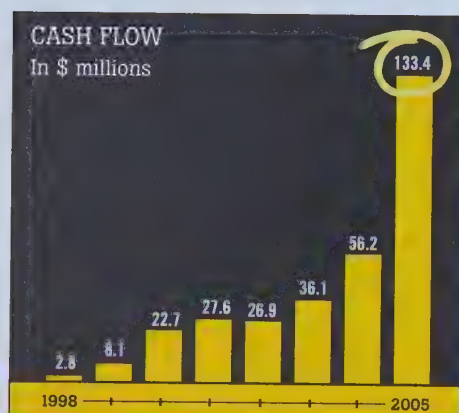
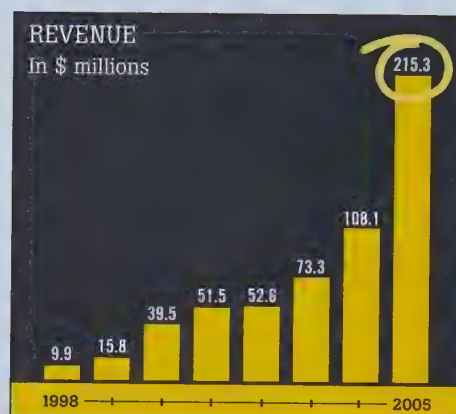
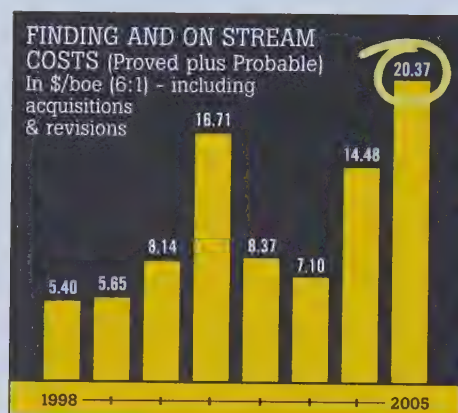
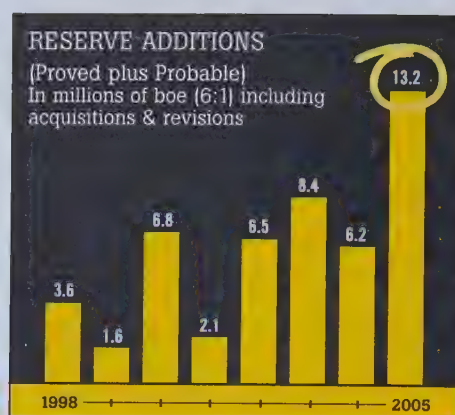
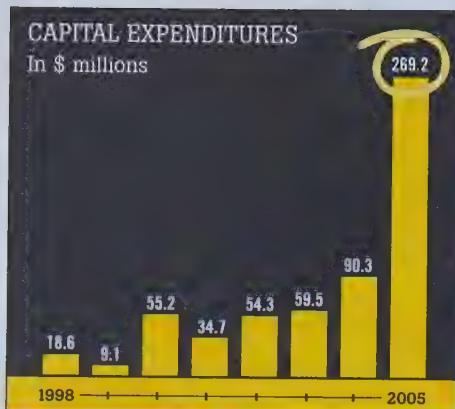


Lowell E. Jackson, P. Eng
PRESIDENT AND CHIEF EXECUTIVE OFFICER



Rodger D. Trimble, P. Eng
VICE PRESIDENT ENGINEERING

(1) Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.



Corporate Governance

Real's Board of Directors is comprised of experienced, proven leaders representing a diverse group of professions and industries in Canada. Together, the Directors work to help Real realize its full potential by sharing their creative vision, initiative and sense of how outside events and developments can affect Real's future. They bring sound judgement, integrity and independence of thought to the task and are encouraged to speak their minds, while respecting others, so that different viewpoints can flourish in the process of developing a sensible consensus.

Our Code of Ethics and Business Conduct (the "Code"), adopted by the Board, expresses fundamental principles that guide the Board in its deliberations and shape Real's activities. The Code applies to the members of the Board, the Chief Executive Officer (CEO), the Chief Financial Officer (CFO) and all employees throughout the organization. It incorporates our guiding principles; upholding the law, honouring trust, fairness, objectivity, confidentiality, integrity and corporate and individual responsibility. It creates a frame of reference for dealing with sensitive and complex issues and provides for accountability if standards of conduct are not upheld.

Real's Board regularly reviews its corporate governance practices in light of developing requirements in this field. As new provisions come into effect, the Board will reassess its corporate governance practices and implement changes where appropriate.

INDEPENDENCE OF THE BOARD

A majority of the Board of Real must be resident Canadians and must qualify as independent and unrelated directors in accordance with Canadian securities laws. Five of the seven members of Real's Board are independent of Real. A sixth Director, Mr. Dallas Droppo is a partner of a law firm which provides legal advisory services to Real and is considered independent for all purposes other than serving on the Audit Committee of the Board. The only related Director is Lowell Jackson, President and Chief Executive Officer of Real. The Board has concluded that Mr. Jackson's dual role does not impair the Board's ability to function independently of management. Mr. Jackson's extensive knowledge of Real's business is beneficial to other members of the Board.

RESPONSIBILITIES OF THE BOARD

Real's Board members are stewards of the organization. The Board of Real oversees the management of the business affairs of Real, discharging its responsibilities either directly, through Board committees or through management. The delegations of authority conform to statutory limitations specifying responsibility of the Board that cannot be delegated to management. Any responsibilities not delegated to management remain with the Board and its committees. The Board encourages Real's management, led by the President and CEO, to be strong leaders and make clear and appropriate executive decisions.

At each regularly scheduled Board meeting, the Board meets without management present to ensure that the Board is able to discharge its responsibilities independent of management.

SHARE HOLDINGS OF BOARD MEMBERS

	Common Shares Owned ⁽¹⁾	Stock Options Held ⁽¹⁾
Martin G. Abbott	281,339	50,000
D. Nolan Blades	35,000	50,000
Frans Burger	408,944	50,000
Dallas L. Droppo	41,450	50,000
Richard N. Edgar	-	-
Lowell E. Jackson	439,981	225,000
Robert B. Michaleski	43,166	8,334

(1) As at March 14, 2006

DISCLOSURE POLICY

Real has a written Disclosure Policy pertaining to dealing with the media and with respect to all continuous disclosure and public reporting requirements to its shareholders and the investment community. Issues arising from this Disclosure Policy are dealt with by a committee of officers of the Corporation consisting of the Chief Executive Officer, the Chief Financial Officer, the Corporate Secretary and the Vice President Land. The disclosed information is released through newswire services, the internet website and mailings to shareholders.

COMMITTEES OF THE BOARD

The Board of Directors has established an Audit Committee, a Compensation Committee, a Health, Safety & Environment Committee, a Reserves Audit Committee, and a Risk Management Committee. Directors, committees or members of a committee have the right to engage an outside advisor at Real's expense. The Board delegates certain work to Board committees. This allows in-depth analysis of issues by the committees and more time for the full Board to discuss and debate items of business. Complete Charters of the Board committees are available on the Corporate Governance section of Real's website at www.realres.com.

Audit Committee

The Audit Committee consists of Martin G. Abbott, Frans Burger and Robert B. Michaleski, all of whom are independent under the Canadian securities laws. The Audit Committee met four times in 2005.

It is critical that the external audit function, a mechanism key to investor protection, is working effectively and efficiently, and that information is being relayed to the Board of Directors in an accurate and timely fashion. The activities of the Audit Committee are fundamental to the process. Accounting for transactions and internal controls lies with senior management with oversight responsibilities vested in the Audit Committee.

The Audit Committee has the authority, to the extent it deems necessary or appropriate, to retain special legal, accounting or other consultants to advise the Audit Committee and carry out its duties, and to conduct or authorize investigations into any matters within its scope of responsibilities. The Audit Committee shall have the authority to set and pay the compensation for any advisors employed by the Audit Committee.

The Audit Committee has established processes for the confidential receipt and handling of employee complaints (Whistleblower Policy) which can be accessed anonymously by fax, regular mail or by hand delivery. Additional information about the Whistleblower Policy can be found on Real's website at www.realres.com.

In addition, the Audit Committee holds in-camera meetings with representatives of the external auditors to discuss audit related issues including the quality of accounting personnel.

The Audit Committee has such other powers and duties as may from time to time by resolution be assigned to it by the Board.

An annual performance evaluation of that Committee is undertaken by the Compensation Committee. The Audit Committee reviews and reassess annually the adequacy of the charter and recommend changes, as appropriate to the Board of Directors.

All members of the Audit Committee must be financially literate (having the ability to understand balance sheets, income statements, cash flow statements and related notes to the consolidated financial statements).

Compensation Committee

The Compensation Committee consists of Martin G. Abbott, D. Nolan Blades, and Robert B. Michaleski, all of whom are independent Directors. The Compensation Committee met three times in 2005.

The Compensation Committee discharges the Board's responsibilities relating to reviewing and assessing the size and composition of the Board and planning its succession, director education, evaluation and compensation. In addition, the Compensation Committee discharges the Board's responsibilities relating to compensation of Real's executives in order to attract, motivate and retain competent executive personnel as well as to review the compensation in aggregate of the Company's full time staff.

Health, Safety and Environment Committee

The Health, Safety and Environment Committee consists of Dallas Droppo and Lowell Jackson, one of whom is independent. The Health, Safety and Environment Committee met four times in 2005.

The Health, Safety and Environment Committee discharges the Board's responsibilities relating to the development, implementation and monitoring of the Company's health, safety and environmental policies.

Reserves Audit Committee

The Reserves Audit Committee consists of Richard Edgar, D. Nolan Blades and Frans Burger all of whom are independent Directors. The Reserves Audit Committee met twice in 2005.

The Reserves Audit Committee discharges the Board's responsibilities relating to the preparation and disclosure of the reserve audit statements, enhancing the Independent Reserves Engineer's independence and performance, increasing the transparency, credibility and objectivity of reserves reporting. In addition, the Reserves Audit Committee discharges the Board's responsibilities for enhancing the communication between management, staff responsible for producing internal reserve information, the Independent Reserves Engineer and the Board.

Risk Management Committee

The Risk Management Committee consists of Frans Burger, Dallas Droppo and Lowell Jackson, two of whom are independent. The Risk Management Committee met four times in 2005.

The Risk Management Committee discharges the Board's responsibilities relating to the assessment, monitoring and management of principal business risks.

DIRECTOR COMPENSATION

The Board, through its Compensation Committee, periodically reviews the adequacy and form of compensation for its Directors. The Board considers their commitment, comparative fees, responsibilities and potential liabilities in determining remuneration. During the 2005 fiscal year, compensation was in the form of an annual honorarium payment of \$10,000 and meeting fees of \$1,000 per meeting. Members of the Audit Committee receive meeting fees of \$1,000 per meeting. In addition, each non-executive Director has been granted options to purchase common shares of the Corporation ("Options") with an exercise price equal to the market price of the Corporation's common shares at the time of the grant.

SUMMARY OF BOARD, COMMITTEE MEETING ATTENDANCE AND TOTAL COMPENSATION PAID

Director	Board ⁽¹⁾ Meetings Attended	Committee ⁽¹⁾ Meetings Attended	Meeting Fees (\$)	Board Retainer (\$)	Total Fees (\$)
Martin G. Abbott	6/8	6/7	12,000	10,000	22,000
D. Nolan Blades	8/8	5/5	13,000	10,000	23,000
Frans Burger	7/8	6/8	14,000	10,000	24,000
Dallas L. Droppo	7/8	5/5	12,000	10,000	22,000
Richard Edgar ⁽²⁾	0/8	0/0	-	-	-
Lowell E. Jackson ⁽³⁾	8/8	8/8	-	-	-
Robert B. Michaleski	7/8	5/5	12,000	10,000	22,000

(1) Meetings attended/total meetings held; includes attendance at a Strategic Planning Meeting

(2) Mr. Richard N. Edgar was appointed to the Board of Directors February 1, 2006 and to the Reserves Audit Committee March 15, 2006. There have been no Reserves Audit Committee meetings held since Mr. Edgar's appointment to that committee.

(3) Lowell E. Jackson is a member of management, and therefore does not receive retainer or meeting fees.

Management's Discussion and Analysis

The following discussion and analysis was prepared on March 14, 2006 and is management's assessment of Real's historical financial and operating results and should be read in conjunction with the audited Consolidated Financial Statements of the Company for the years ended December 31, 2005 and 2004 together with the notes related thereto. The reader should be aware that historical results are not necessarily indicative of future performance. This discussion contains certain forward-looking statements and forward-looking information which are based on the Company's current internal expectations, estimates, projections, assumptions and beliefs. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "plan", "should", "believe", and similar expressions are intended to identify forward-looking statements and forward-looking information. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements or information. The Company believes the expectations reflected in those forward-looking statements and information are reasonable but no assurance can be given that these expectations will prove to be correct, and such forward-looking statements and information included in this discussion should not be unduly relied upon. Such forward-looking statements and information speak only as of the date of this discussion and the Company does not undertake any obligation to publicly update or revise any forward-looking statements or information, except as required by applicable laws.

In particular, this discussion contains forward-looking statements and information pertaining to the following:

- the quality of and future net revenues from our reserves;
- oil, NGL and natural gas production levels;
- commodity prices, foreign currency exchange rates and interest rates;
- capital expenditure programs and other expenditures;
- supply and demand for oil, NGL and natural gas;
- expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions and development;
- schedules and timing of certain projects and the Company's strategy for growth;
- the Company's future operating and financial results; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

The Company's actual results could differ materially from those anticipated in these forward-looking statements and information as a result of both known and unknown risks, including the risk factors set forth under "Risks and Uncertainties" in this discussion and those set forth below:

- volatility in market prices for oil, NGL and natural gas;
- changes or fluctuations in oil, NGL and natural gas production levels;
- changes in foreign currency exchange rates and interest rates;
- changes in capital and other expenditure requirements and debt service requirements;
- liabilities and unexpected events inherent in oil and gas operations, including geological, technical, drilling and processing problems;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;

- the Company's success at acquisition, exploitation and development of reserves;
- changes in general economic, market and business conditions in Canada, North America and worldwide;
- actions by governmental or regulatory authorities including changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- changes in environmental or other legislation applicable to the Company's operations, and the Company's ability to comply with current and future environmental and other laws.

Many of these risk factors and other specific risks and uncertainties are discussed in further detail throughout this discussion and analysis for the year ended December 31, 2005 and the Annual Information Form. Additional information related to the Company, including the Company's Annual Information Form, is available through the internet on the Company's SEDAR profile at www.sedar.com. Readers are also referred to the risk factors described in this discussion under "Risks and Uncertainties" and in other documents the Company files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the Company.

FINANCIAL HIGHLIGHTS OF 2005

The Company again achieved record activity levels in 2005, concluding a successful drilling program that resulted in the seventh consecutive year of growth in production revenue and total production volumes. The growth in 2005 was accomplished primarily through the drill bit with an equal emphasis on crude oil and natural gas prospects. The Company also completed the acquisition of producing properties in the Carnduff/Hastings area of Southeast Saskatchewan early in the second quarter of 2005 and an acquisition of producing properties in the Ferrybank area of Central Alberta late in the fourth quarter of 2005. The Company continues to maintain a balance between crude oil and natural gas production with an even split between the two commodities.

DETAILED FINANCIAL ANALYSIS

PRODUCTION REVENUE

(\$ thousands)	Years ended December 31		
	2005	2004	% change
Crude oil and liquids revenue	110,638	52,896	109
Natural gas revenue	103,960	58,990	76
	214,598	111,886	92
Hedging losses	-	(4,481)	(100)
Royalty income	673	698	(4)
Total production revenue	215,271	108,103	99

Production revenue from crude oil, liquids and natural gas sales increased by \$107.2 million or 99 percent to \$215.3 million in 2005 from \$108.1 million in 2004. Higher total production volumes resulting in total production of 10,394 boe/d and higher commodity prices contributed equally to the increase in production revenue. The variance analysis table following the price analysis summarizes the factors contributing to the increase.

Average crude oil and liquids production for the year increased by 1,859 bbls/d (56 percent) to 5,152 bbls/d from 3,293 bbls/d in 2004. The successful 2005 drilling program added crude oil production in several of the Company's core areas. Southeast Saskatchewan (Alida/Cantal and Carnduff), West Central Alberta (Virginia Hills and Sakwatamau) and Central Alberta (Ferrybank) all contributed to increased production levels through the drill bit. Additional production was also recorded as a result of the producing property acquisition completed in the second quarter of 2005 in the Carnduff area of Southeast Saskatchewan. These additions were marginally offset by lower production in the East Central Alberta core area (Consort/Neutral Hills) due to natural declines. Average natural gas production for the year increased by 7.0 mmcf/d (28 percent) to 31.5 mmcf/d from 24.5 mmcf/d in 2004. Natural gas production additions arising from the 2005 drilling program were recorded in West Central Alberta (Virginia Hills, Judy Creek and Sturgeon Lake), Southern Alberta (Pageant), and Central Alberta (Ferrybank and Crystal). These increases were partially offset by expected declines in the Scandia area of Southeast Alberta.

The following table summarizes the commodity prices realized during 2005 and 2004:

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AVERAGE REALIZED PRICE

	Years ended December 31		
	2005	2004	% change
Crude oil and liquids (\$/bbl, excluding hedging)	58.85	43.89	34
Crude oil and liquids (\$/bbl, including hedging)	58.85	41.45	42
Natural gas (\$/mcf, excluding hedging)	9.06	6.58	38
Natural gas (\$/mcf, including hedging)	9.06	6.41	41
Total average realized price (\$/boe, including hedging)	56.57	39.80	42

.....

AVERAGE REALIZED PRICE

(\$/boe)	Years ended December 31		
	2005	2004	% change
Production revenue	56.57	41.46	36
Hedging losses	-	(1.66)	(100)
	56.57	39.80	42
Royalty income	0.18	0.26	(31)
Total average realized price	56.75	40.06	42

West Texas Intermediate (WTI) is the benchmark for North American oil prices and is the crude type against which NYMEX futures contracts are priced. Canadian crude oil prices are based upon refiners' postings at Alberta hubs such as Edmonton and Hardisty. These postings represent the WTI price at Cushing, Oklahoma less a transportation differential, the Canadian/US foreign exchange rate, and an adjustment for regional market conditions.

Real's average field prices reflect the refiners' posted price at the market centers less adjustments for product quality relative to the posted product and includes the quality differential on natural gas liquids.

CRUDE OIL AND LIQUIDS PRICES

(\$/bbl, excluding hedging)

	Years ended December 31		
	2005	2004	% change
WTI (\$US)*	56.56	41.40	37
Average exchange rate (\$Cdn/\$US)*	1.21	1.30	(7)
WTI (converted to \$Cdn)	68.44	53.82	27
Differential WTI to Edmonton (\$Cdn)	0.28	(1.28)	(78)
Edmonton light sweet posting (\$Cdn)*	68.72	52.54	31
Quality differential (including NGL differential)	(9.87)	(8.65)	14
Average realized price (\$Cdn)	58.85	43.89	34

*Source – CAPP Crude Oil Report – Refiner postings, Bank of Canada noon spot rate

The sizable increase in the WTI benchmark price for crude oil during 2005 was partially offset by the impact of the strengthening of the Canadian dollar. The Company realized an average crude oil and liquids price of \$58.85 per bbl in 2005, 34 percent higher than the \$43.89 per bbl realized in 2004. The quality differential for crude oil and liquids increased in 2005 due to the higher relative increase in WTI postings compared to the Edmonton sweet price. These increases were partially offset by improved crude oil differentials resulting from a change in marketing arrangements, primarily in the Hays/Enchant area of Southern Alberta.

Alberta natural gas prices are typically referenced to AECO "C".

NATURAL GAS PRICES

(\$/mcf, excluding hedging)

	Years ended December 31		
	2005	2004	% change
AECO "C" *	8.77	6.55	34
Variance: Real pool price vs. spot	0.29	0.03	867
Average realized natural gas price	9.06	6.58	38

*Source – CAPP Natural Gas Report – calendar month average of daily cash prices (weighted)

A 34 percent increase in average AECO "C" prices was the primary contributing factor in the increase in average realized prices of \$9.06 per mcf in 2005 compared to \$6.58 per mcf in 2004. A change in the composition of the Company's natural gas production also contributed to the increase in prices by increasing the variance between the Company's average pool price and the spot price. New production coming on in West Central Alberta core area has a higher heating content and consequently commands a premium over AECO.

The following table summarizes the impact of the Company's production activities, prices and hedging activities on oil and gas revenue:

VARIANCE ANALYSIS

	(\$ Millions)	% change
Reported 2004 production revenue	108.1	
Increase due to crude oil and liquids volumes	29.6	28
Increase due to realized gas price	28.4	27
Increase due to realized crude oil and liquids price	28.1	26
Increase due to gas production volumes	16.6	15
Increase due to hedging activities	4.5	4
Total increase, net	107.2	100
Reported 2005 production revenue	215.3	

ROYALTY EXPENSE

Royalties increased by 79 percent to \$41.4 million in 2005 from \$23.1 million in 2004. Increased royalties associated with higher oil and gas revenues were partially offset by the impact of the eligibility of certain wells for Crown royalty holidays. Freehold and GORR royalties were lower due to the change in the composition of the production and several wells that were royalty-free during the year pending capital expenditure recoveries. The impact of these factors caused total royalties (net of ARTC) as a percentage of gross revenue to decrease to 19.2 percent in 2005 from 20.6 percent in 2004.

ROYALTY EXPENSE

(\$ thousands, except where noted)	Years ended December 31		
	2005	2004	% change
Crown	29,262	16,198	81
Freehold and GORR	12,585	7,312	72
Total royalties	41,847	23,510	78
ARTC	(487)	(443)	10
Total royalties, net of ARTC	41,360	23,067	79
Total royalties (\$/boe)	11.03	8.71	27
Total royalties, net of ARTC (\$/boe)	10.90	8.55	27

AVERAGE ROYALTY RATES

(% of revenue, excluding hedging activities)	Years ended December 31		
	2005	2004	% change
Crown	13.6	14.5	(6)
Freehold and GORR	5.8	6.5	(11)
Total royalties	19.4	21.0	(8)
ARTC	(0.2)	(0.4)	(50)
Total royalties, net of ARTC	19.2	20.6	(7)

OPERATING EXPENSES

Operating expenses in 2005 increased by 37 percent to \$27.5 million from \$20.0 million in 2004 due to increased production volumes. Operating expenses on a unit-of-production basis decreased to \$7.25 per boe in 2005 from \$7.42 per boe in 2004. There was upward pressure on the overall operating costs structure throughout 2005 that was directly related to increased industry activity in Western Canada. This increase was more than offset by the reduction in unit costs resulting from the change in the composition of production. There was a higher proportion of natural gas production coming from West Central Alberta and Central Alberta where processing costs are lower. As well, there was a proportionate increase in crude oil production coming from Southeast Saskatchewan where operating costs are lower.

OPERATING EXPENSES

(\$ thousands, except where noted)	Years ended December 31		
	2005	2004	% change
Operating expenses	27,502	20,019	37
Operating expenses (\$/boe)	7.25	7.42	(2)

TRANSPORTATION COSTS

Transportation costs in 2005 increased by 54 percent to \$2.9 million from \$1.9 million in 2004, primarily as a result of increased production volumes. Transportation costs on a unit-of-production basis increased nine percent to \$0.76 per boe in 2005 from \$0.70 per boe in 2004. The unit-of-production rate increased primarily due to higher trucking costs for oil resulting from a change in crude oil marketing arrangements primarily in the Hays/Enchant area of Southern Alberta. This increase in costs was more than offset by lower quality differentials on crude oil that directly resulted in higher netbacks.

TRANSPORTATION COSTS

(\$ thousands, except where noted)	Years ended December 31		
	2005	2004	% change
Transportation costs	2,898	1,879	54
Transportation costs (\$/boe)	0.76	0.70	9

OPERATING NETBACK

Operating netbacks (excluding hedging losses and ARTC) increased 52 percent to \$37.71 per boe for 2005 compared to \$24.89 per boe for 2004. This increase was primarily due to higher realized commodity prices and, to a lesser extent, lower operating costs and royalty rates.

OPERATING NETBACK*

(\$/boe)	Years ended December 31		
	2005	2004	% change
Production revenue (excluding hedging losses)	56.57	41.46	36
Royalty income	0.18	0.26	(31)
	56.75	41.72	36
Total royalties (excluding ARTC)	(11.03)	(8.71)	27
Operating expenses	(7.25)	(7.42)	(2)
Transportation costs	(0.76)	(0.70)	9
Operating netback	37.71	24.89	52

* (\$/boe, includes natural gas production converted on a basis of 6 mcf equals 1 bbl)

OPERATING NETBACK – CRUDE OIL PROPERTIES

(\$/bbl)	Years ended December 31		
	2005	2004	% change
Production revenue (excluding hedging losses)	58.66	43.77	34
Royalty income	0.14	0.27	(48)
	58.80	44.04	34
Total royalties (excluding ARTC)	(10.39)	(8.49)	22
Operating expenses	(9.48)	(9.58)	(1)
Transportation costs	(0.76)	(0.41)	85
Operating netback	38.17	25.56	49

OPERATING NETBACK – NATURAL GAS PROPERTIES**

	Years ended December 31		
	2005	2004	% change
Production revenue (excluding hedging losses)	9.22	6.69	38
Royalty income	0.03	0.04	(25)
	9.25	6.73	37
Total royalties (excluding ARTC)	(1.90)	(1.47)	29
Operating expenses	(0.99)	(1.03)	(4)
Transportation costs	(0.13)	(0.14)	(7)
Operating netback	6.23	4.09	52

** (\$/mcf, includes natural gas liquids production converted on basis of 1 bbl equals 6 mcf)

GENERAL AND ADMINISTRATIVE EXPENSES

Gross general and administrative expenses increased 56 percent to \$11.9 million in 2005 compared to \$7.7 million in 2004. The increase is primarily due to increased staffing levels associated with the Company's ongoing growth. Included in the first quarter of 2005 was a one-time charge of \$0.6 million related to a corporate restructuring. On a unit-of-production basis, net general and administrative expenses increased 16 percent to \$1.64 per boe from \$1.41 per boe.

GENERAL AND ADMINISTRATIVE EXPENSES

(\$ thousands)	Years ended December 31		
	2005	2004	% change
Gross expense	11,930	7,666	56
Overhead recoveries	(3,114)	(1,926)	62
Subtotal	8,816	5,740	54
Capitalized expense	(2,607)	(1,943)	34
Net expense	6,209	3,797	64

AVERAGE COST PER BARREL OF OIL EQUIVALENT

(\$/boe)	Years ended December 31		
	2005	2004	% change
Gross expense	3.14	2.84	11
Overhead recoveries	(0.82)	(0.71)	15
Subtotal	2.32	2.13	9
Capitalized expense	(0.68)	(0.72)	(6)
Net expense	1.64	1.41	16

STOCK-BASED COMPENSATION

Stock-based compensation costs increased significantly in 2005 from 2004, a function of the amortization of the expenses associated with options that were granted during 2005 as a part of the normal compensation program. The valuation of these options increased primarily due to higher strike prices (based on the Black-Scholes option pricing model).

STOCK-BASED COMPENSATION

(\$ thousands, except where noted)	Years ended December 31		
	2005	2004	% change
Stock-based compensation	1,437	446	222
Stock-based compensation (\$/boe)	0.38	0.17	124

INTEREST EXPENSE

Interest expense for 2005 decreased 17 percent to \$1.8 million from \$2.1 million in 2004. Average debt levels during 2005 were 20 percent lower than during 2004. The all-inclusive cost of borrowing averaged 4.2 percent in 2005 compared to 4.1 percent in 2004.

INTEREST EXPENSE

(\$ thousands, except where noted)	Years ended December 31		
	2005	2004	% change
Interest expense	1,776	2,141	(17)
Interest expense (\$/boe)	0.47	0.79	(41)
Average debt outstanding	41,800	52,000	(20)
Average effective interest rate (%)	4.2	4.1	2

DEPLETION, DEPRECIATION AND ACCRETION ("DD&A")

DD&A expense increased 94 percent to \$58.6 million in 2005 from \$30.3 million in 2004 almost equally based on higher production levels and a higher average depletion rate per boe. The DD&A increased to \$15.45 per boe during 2005 compared to \$11.22 per boe in 2004. Increased overall industry activity during the last year has put upward pressure on capital costs and the inclusion of the future income tax gross-up on the corporate and property acquisition (note 3 to the financial statements) has also contributed to higher DD&A rates.

DEPLETION, DEPRECIATION AND ACCRETION

(\$ thousands, except where noted)	Years ended December 31		
	2005	2004	% change
Depletion and depreciation	57,638	29,396	96
Accretion on asset retirement obligation	971	873	11
	58,609	30,269	94
Depletion, depreciation and accretion (\$/boe)	15.45	11.22	38

CEILING TEST

Real performs a ceiling test calculation at least annually in accordance with the Canadian Institute of Chartered Accountants' full cost accounting guidelines. The recovery of costs is tested by comparing the carrying amount of the oil and natural gas assets to the undiscounted cash flows from those assets using proved reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, then an impairment would be recognized on the amount by which the carrying amount of the assets exceeds the present value of expected cash flows using proved and probable reserves and expected future prices and costs. No write-down was required for the years ended December 31, 2005 and December 31, 2004. The following table summarizes the expected future commodity prices that were used in the ceiling test calculation:

	Years ended December 31					
	Oil Price		Gas Price		NGL Price	
	2005	2004	2005	2004	2005	2004
2005	-	44.77	-	6.63	-	39.11
2006	62.16	42.51	10.35	6.34	54.63	36.59
2007	59.22	39.58	9.31	6.07	52.08	33.71
2008	56.33	36.69	8.12	5.80	49.60	30.80
2009	53.48	34.40	7.50	5.53	47.21	29.04
2010	50.69	34.86	6.88	5.64	44.41	29.58
Thereafter	53.99	39.51	8.12	6.75	49.11	32.62
Average	56.12	39.83	8.49	6.39	50.15	33.78

TAXES

The Company's future income tax expense was \$24.7 million in 2005, an increase of 158 percent from the \$9.5 million recorded in 2004. This increase was primarily due to higher production revenues related to the increase in both production volumes and prices which accounted for an \$18.9 million increase in future tax expense. This increase was partially offset by an additional reduction in the federal rate of two percent. This relates to the CRA previously announced scheduled reduction in federal corporate income tax rates (see (e) in the Future Income Tax discussion in Critical Accounting Estimates).

The Company's capital tax expense of \$1.8 million for 2005 represents an increase of 123 percent from \$0.8 million in the preceding year. This was due to the net increase in Large Corporation Tax base resulting from the Company's growth and the additional Saskatchewan surcharge from the properties acquired in the Carnduff/Hastings acquisition. Real paid no current income tax in 2005.

TAXES

(\$ thousands, except where noted)	Years ended December 31		
	2005	2004	% change
Future income taxes	24,659	9,543	158
Effective income tax rate (%)	32.7	36.0	(9)
Capital taxes	1,756	787	123
Total taxes	26,415	10,330	156
Total taxes (\$/boe)	6.96	3.83	82

At the end of 2005, Real had approximately \$226.2 million of accumulated tax pools that are available for deduction against future earnings compared to \$132.8 million at December 31, 2004.

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SUMMARY OF TAX POOLS AT DECEMBER 31, 2005

(\$ thousands)	Maximum Available Balance	Maximum Annual Deduction
Canadian exploration expense	1,301	100%
Canadian development expense	68,136	30%
Canadian oil & gas property expense	84,287	10%
Undepreciated capital cost	65,520	4-30%
Foreign exploration & development expense	314	10%
Share issue costs	6,634	20%
Other	7	7%
Total	226,199	

NET EARNINGS, NETBACKS AND CASH FLOW FROM OPERATIONS

Net Earnings

Net earnings increased 204 percent to \$49.1 million in 2005 from \$16.2 million in 2004. Net earnings per basic share increased 140 percent to \$1.44 per share in 2005 from \$0.60 per share in 2004. Similarly, net earnings per diluted share increased 141 percent to \$1.40 per share in 2005 from \$0.58 per share in 2004.

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NETBACKS

(\$/boe)	Years ended December 31		
	2005	2004	% change
Production revenue	56.75	40.06	42
Net royalties	(10.90)	(8.55)	27
Operating expenses	(7.25)	(7.42)	(2)
Transportation costs	(0.76)	(0.70)	9
Operating netback	37.84	23.39	62
General and administrative expenses	(1.64)	(1.41)	16
Interest expense	(0.47)	(0.79)	(41)
Current taxes	(0.46)	(0.29)	59
Cash flow netback (before abandonment)	35.27	20.90	69
Depletion, depreciation and accretion	(15.45)	(11.22)	38
Future income taxes	(6.50)	(3.54)	84
Stock-based compensation	(0.38)	(0.17)	124
Corporate netback (before abandonment)	12.94	5.97	117

CASH FLOW FROM OPERATIONS

Cash flow from operations increased 138 percent to \$133.4 million in 2005 from \$56.2 million in 2004. Cash flow from operations per basic share increased 88 percent to \$3.92 per share in 2005 from \$2.09 per share in 2004. Cash flow from operations per diluted share increased 87 percent to \$3.79 per share from \$2.03 per share.

(\$ thousands)	Years ended December 31		
	2005	2004	% change
Net earnings	49,065	16,155	204
Non cash items:			
Depletion, depreciation and accretion	58,609	30,269	94
Future income tax expense	24,659	9,543	158
Stock-based compensation	1,437	446	222
Abandonment expenditures	(355)	(240)	48
Cash flow from operations	133,415	56,173	138

(thousands)	Years ended December 31		
	2005	2004	% change
Weighted average outstanding shares			
Basic	34,031	26,932	26
Diluted	35,170	27,724	27
Outstanding shares at December 31			
Basic	37,252	29,090	28
Diluted	38,391	29,882	28

PER SHARE INFORMATION

(\$ thousands, except where noted)	Years ended December 31		
	2005	2004	% change
Net earnings	49,065	16,155	204
Basic (\$/share)	1.44	0.60	140
Diluted (\$/share)	1.40	0.58	141
Cash flow from operations	133,415	56,173	138
Basic (\$/share)	3.92	2.09	88
Diluted (\$/share)	3.79	2.03	87
Total assets	529,681	279,656	89
Basic (\$/share)	15.56	10.38	50
Diluted (\$/share)	15.06	10.09	49
Book value (shareholders' equity)	322,084	143,994	124
Basic (\$/share)	9.46	5.35	77
Diluted (\$/share)	9.16	5.19	76

CAPITAL EXPENDITURES

Real executes its growth strategy through exploration, exploitation and development activities supplemented with strategic property and corporate acquisitions. Net capital expenditures in 2005 before asset retirement obligation and future tax gross-ups were \$269.2 million compared to \$90.3 million in 2004. A larger proportion of capital expenditures were directed towards lease acquisitions and geological and geophysical expenditures than has been recorded historically. This was the direct result of the pre-drilling investment that was made in the Virginia Hills discovery in the West Central Alberta core area. These expenditures are summarized as follows:

CAPITAL EXPENDITURES

(\$ thousands)	Years ended December 31		
	2005	2004	% change
Exploration and development expenditures			
Lease acquisitions	35,629	13,378	166
Geological and geophysical	31,535	5,635	460
Drilling and completion	99,737	50,545	97
Facilities and equipment	33,022	20,768	59
Total exploration and development expenditures	199,923	90,326	121
Other expenditures	778	294	165
Gross capital expenditures	200,701	90,620	121
Corporate acquisition (note 3)	31,606	-	100
Property acquisitions (note 3)	36,938	-	100
Proceeds from property dispositions	(78)	(309)	(75)
Net capital expenditures before the following:	269,167	90,311	198
Asset retirement obligation	3,187	1,195	167
Asset retirement obligation on corporate acquisition	458	-	100
Future income tax gross-up on corporate acquisition	13,709	-	100
Future income tax gross-up on property acquisitions	5,666	-	100
Net capital expenditures	292,187	91,506	219

Funding for capital expenditures and acquisitions was provided for primarily by cash flow from operations and the proceeds from the issuance of equity and, to a lesser extent, working capital.

CAPITALIZATION AND FINANCIAL RESOURCES

At December 31, 2005 the Company had a \$150 million financing commitment with three syndicated Canadian chartered banks, which provided for an extendible revolving term credit facility. At the end of the year, Real had drawn \$35.2 million of the facility.

In addition to this debt, Real had a working capital deficiency of \$33.4 million for a total net debt of \$68.6 million. The ratio of total net debt as at December 31, 2005 to 2005 cash flow was 0.5 times and the ratio of total net debt as at December 31, 2005 to the annualized fourth quarter 2005 cash flow was 0.4 times.

The Company anticipates no unusual working capital requirements in 2006. There are currently no capital commitments and no known unusual trends or liquidity issues at March 14, 2006. The Company expects to be able to meet future obligations associated from ongoing operations from cash flow from operations and amounts that are currently available under the consolidated syndicated and operating facility.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of common shares without par value, and an unlimited number of first, second, third and fourth class preferred shares issuable in series. As at December 31, 2005, Real had 37.3 million outstanding common shares compared to 29.1 million outstanding shares at December 31, 2004. Real had no preferred shares outstanding during these periods. Employees and directors have been granted options to purchase common shares under the Company Stock Option Plan. This plan and its terms and outstanding balance are disclosed in note 6(f) to the Consolidated Financial Statements.

The Company obtained regulatory approval under Canadian securities laws to purchase common shares under four consecutive Normal Course Issuer Bids ("Bid") which commenced in June 2002 and will continue until June 2006. In 2005, Real has not purchased any shares under the current Bid. As of December 31, 2005, Real was entitled to purchase for cancellation an additional 1.7 million common shares under the current Bid.

CONTRACTUAL OBLIGATIONS

The Company has entered into various commitments primarily related to the Calgary office lease. The following table summarizes the outstanding contractual obligations of the Company for the next five years and thereafter:

(\$ thousands)	2006	2007	2008	2009	2010	Thereafter	Total
Office lease	407	443	563	930	1,070	2,587	6,000
Pipeline transportation	117	-	-	-	-	-	117
Other	238	131	8	-	-	-	377
	762	574	571	930	1,070	2,587	6,494

OFF-BALANCE SHEET ARRANGEMENTS AND RELATED PARTY TRANSACTIONS

The Company has not entered into any off-Balance Sheet transactions or into any related party transactions.

CRITICAL ACCOUNTING ESTIMATES

Management is often required to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. A comprehensive discussion of the Company's significant accounting policies is contained in note 2 to the annual Consolidated Financial Statements. The following is a discussion of the accounting estimates that are critical in determining the Company's financial results.

(a) Full cost accounting

The Company follows the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproven properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depletion and depreciation expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point the costs are included in the total cost base for purposes of calculating depletion and for evaluating impairment.

The alternative method of accounting for oil and natural gas properties and equipment is the successful efforts method. The major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs are charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment.

(b) Oil and natural gas reserves

The Company's proved oil and gas reserves are 100 percent evaluated and reported by an independent petroleum engineering consultant. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation. A revision to the reserve estimate could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment under the ceiling test.

(c) Full cost accounting ceiling test

The carrying value of property, plant and equipment is reviewed annually for impairment. Impairment is determined when the carrying value of the Company's property, plant and equipment exceeds the sum of the undiscounted cash flows expected to result from the Company's proved reserves. Cash flows are calculated based on third-party quoted forward prices and are adjusted for the Company's contract prices and quality differentials. If impairment is deemed to occur, the magnitude is calculated by comparing the carrying value of property, plant and equipment to the estimated net present value of future cash flows from proved plus probable reserves. A risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value above the net present value of future cash flows would be recorded as a permanent impairment and charged as additional depletion expense in the Consolidated Statement of Earnings. No write-down was required at December 31, 2005.

(d) Asset retirement obligation

The Company recognizes the fair value of its asset retirement obligation ("ARO") in the period in which it is incurred and when a reasonable estimate of its obligation can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period with the passage of time and the amount of this accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual cost incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which the settlement occurs.

Determinations of the original undiscounted costs are based on engineering estimates using current costs and technology in accordance with existing legislation and industry practice. The estimation of these costs can be affected by factors such as the number of wells drilled, well depth and area-specific environmental legislation.

(e) Future income tax

The Company follows the liability method of accounting for income taxes. Under this method income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the

financial statements and their respective tax base, using substantively enacted future income tax rates. In June 2003, the Federal Government introduced a gradual reduction in the general corporate income tax rate over a five year period starting January 1, 2003 (see Taxes in the MD&A). The impact of the new Federal legislation requires the Company to schedule all existing temporary differences, identify the accounting and tax values during the five-year phase-in period for the declining tax rates and recalculate the future income tax balance using tax rates in effect when temporary differences reverse. The above-noted forecasts of estimated net revenue streams are utilized to calculate the future tax provision and, as such, are subject to revisions, both upwards and downwards, that are not known at this time. In addition to these revisions, future capital activities can impact the timing of the reversal of any temporary differences. These differences can have an impact on the amount of future taxes determined at a point in time. To the extent that these differences are created, they can impact the charge against earnings for future income taxes.

(f) Stock-based compensation

The Company's Stock Option Plan provides for the granting of options to directors, officers and employees. The Company uses the fair value method for valuing stock option grants. Compensation costs attributable to share options granted are measured at fair value at the grant date and are expensed over the expected vesting time-frame with a corresponding increase to contributed surplus. Upon exercise of stock options, consideration paid by the option holder, together with the amount previously recognized in contributed surplus, is recorded as an increase in share capital.

IMPACT OF NEW ACCOUNTING PRONOUNCEMENTS

There are no new accounting pronouncements which currently impact the Consolidated Financial Statements of Real.

RISKS AND UNCERTAINTIES

There are a number of risks facing participants in the Canadian oil and gas industry. Some of the risks are common to all businesses while others are specific to the sector. The following discussion reviews the general and specific risks as well as Real's approach to managing these risks.

The Company is engaged in the exploration, development, production and acquisition of crude oil and natural gas. Real's business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, and currency exchange rates. Operational risks include competition, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns.

The Company minimizes its business risks by operating a large number of its properties. This enables Real to control the timing, direction and costs related to exploration and development opportunities. Real's geological focus is on areas in which the prospects are well understood by management. Technological tools are regularly used to reduce risk and increase the probability of success. The Company closely follows all government regulations and has an up-to-date emergency response plan that has been communicated to field operations by management. Real also carries insurance coverage to protect itself against potential losses. Maintaining a highly motivated and talented staff of petroleum and natural gas professionals further minimizes the business risk.

Real relies on various sources of funding to support its growing capital expenditure program:

- Internally-generated cash flow provides a minimum level of funding on which the Company's annual capital expenditure program is based;
- Debt may be utilized to expand capital programs when appropriate; and
- New equity, if available on favourable terms, may be utilized to expand exploration programs.

The Company is exposed to commodity price and market risk for its principal products of petroleum and natural gas. Commodity prices are influenced by a wide variety of factors, most of which are beyond Real's control. To manage this risk, the Company has in the past entered into a number of short-term financial derivatives for hedging purposes. These derivatives included contracts related to oil and gas prices, as well as foreign exchange rates. Real has also minimized its exposure to increased rates by entering into short-term contracts for interest rate swap. The Company continues to monitor the cost and associated benefit of these instruments as well as debt levels and utilization rates on bank lines and will utilize these derivatives when warranted.

Inflation risks subject the Company to potential erosion of product netbacks. For example, increasing domestic prices for oil and natural gas production equipment and services can inflate the costs of operations.

The supply of service and production equipment at competitive prices is critical to the ability to add reserves at a competitive cost and produce them in an economic and timely fashion. In periods of increased activity, these services and supplies can become difficult to obtain. The Company attempts to mitigate this risk by developing strong long-term relationships with suppliers and contractors and maintaining an appropriate inventory of production equipment.

Demand for crude oil and natural gas produced by the Company exists within Canada and the United States; however, crude oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Demand for natural gas liquids is influenced mainly by the demand for petrochemicals in North American and off-shore markets. Real mitigates these risks as follows:

- Crude oil production is of a high quality and hence not subject to adverse quality differentials;
- Natural gas is connected to a mature pipeline infrastructure that operates with minimal interruptions;
- Exploration efforts target high-quality oil and liquids-rich natural gas reserves;
- Exploration efforts are concentrated in core regions where marketing expertise levels are highest. Marketing synergies can be achieved with the existing production base;
- Sale arrangements vary in term and pricing structure creating a diverse portfolio that minimizes risk of exposure to any one market; and
- Financial instruments may be used where appropriate to manage commodity price volatility.

In 1994, the United Nations' Framework on Climate Change came into force and three years later led to the Kyoto Protocol, which requires nations to reduce their emissions of carbon dioxide and, therefore, greenhouse gases. The Government of Canada has ratified the Kyoto Protocol. Producers in geographic areas where Real operates may be required to reduce greenhouse gases. This could result in, among other things, increased operating and capital expenditures for those producers. This could make certain production of crude oil or natural gas by those producers uneconomic, resulting in reductions in such production. The Company is unable to predict the effect on its future earnings of the ratification of the Kyoto Protocol by the Federal Government.

The Company is committed to maximizing shareholder value in an environmentally and socially responsible and safe manner. To this end, Real is actively involved in the Canadian Petroleum Producers (CAPP) Stewardship initiative. This voluntary initiative encourages members to continually improve their environment, health and safety performance and to report their progress to all stakeholders. The Company is pleased to report that CAPP has recognized Real's participation at a Platinum level, which acknowledges an open and transparent account of our environment, health and safety performance on a yearly basis and a leadership role in the improvement of these issues.

SELECTED ANNUAL INFORMATION

(\$ thousands, except per share amounts)	Years ended December 31		
	2005	2004	2003
Working interest production			
Crude oil and liquids (bbls/d)	5,152	3,293	3,352
Natural gas (mcf/d)	31,451	24,478	12,833
Total oil equivalent (boe/d)	10,394	7,373	5,491
Production revenue	215,271	108,103	73,282
Cash flow from operations	133,415	56,173	36,142
Per share – basic	3.92	2.09	1.58
Per share – diluted	3.79	2.03	1.56
Net earnings	49,065	16,155	14,597
Per share – basic	1.44	0.60	0.64
Per share – diluted	1.40	0.58	0.63
Total assets	529,681	279,656	211,967
Total net debt	68,571	58,498	67,697

SUMMARY OF QUARTERLY RESULTS

(\$ thousands, except per share amounts)	Three months ended 2005				Annual
	March 31	June 30	September 30	December 31	2005
Working interest production					
Crude oil and liquids (bbls/d)	4,150	5,198	5,290	5,945	5,152
Natural gas (mcf/d)	25,998	32,532	32,521	34,645	31,451
Total oil equivalent (boe/d)	8,483	10,620	10,710	11,719	10,394
Production revenue	35,259	49,443	60,804	69,765	215,271
Cash flow from operations	19,570	32,234	38,767	42,844	133,415
Per share – basic	\$ 0.66	\$ 0.98	\$ 1.11	\$ 1.17	\$ 3.92
Per share – diluted	\$ 0.64	\$ 0.94	\$ 1.07	\$ 1.14	\$ 3.79
Net earnings	5,775	11,903	13,579	17,808	49,065
Per share – basic	\$ 0.20	\$ 0.36	\$ 0.39	\$ 0.49	\$ 1.44
Per share – diluted	\$ 0.19	\$ 0.35	\$ 0.38	\$ 0.48	\$ 1.40
Total assets	335,732	431,685	474,766	529,681	529,681
Total net debt	68,305	87,631	43,915	68,571	68,571

(\$ thousands, except per share amounts)	Three months ended 2004				Annual 2004
	March 31	June 30	September 30	December 31	
Working interest production					
Crude oil and liquids (bbls/d)	3,281	3,090	3,017	3,783	3,293
Natural gas (mcf/d)	21,784	23,617	25,113	27,360	24,478
Total oil equivalent (boe/d)	6,911	7,027	7,203	8,344	7,373
Production revenue	22,869	25,546	26,966	32,722	108,103
Cash flow from operations	11,420	12,791	14,653	17,309	56,173
Per share – basic	\$ 0.47	\$ 0.46	\$ 0.53	\$ 0.63	\$ 2.09
Per share – diluted	\$ 0.46	\$ 0.45	\$ 0.52	\$ 0.60	\$ 2.03
Net earnings	3,004	3,313	3,863	5,975	16,155
Per share – basic	\$ 0.12	\$ 0.12	\$ 0.14	\$ 0.22	\$ 0.60
Per share – diluted	\$ 0.12	\$ 0.12	\$ 0.13	\$ 0.21	\$ 0.58
Total assets	227,636	245,579	265,295	279,656	279,656
Total net debt	51,509	63,607	75,540	58,498	58,498

FOURTH QUARTER 2005 RESULTS

Capital expenditures totalled \$68.0 million for the fourth quarter and included drilling 34 (26.7 net) wells. Real spent \$25.3 million on land and property acquisitions, \$10.8 million on seismic, \$24.1 million on drilling and completions and \$7.8 million on facilities. The capital program was financed through a combination of funds generated from operations and working capital.

Operationally, Real increased its average production to 11,719 boe/d in the fourth quarter from 10,710 boe/d in the third quarter of 2005. Consistent with increased production, Real recorded gains in production revenue, cash flow from operations and net income in the fourth quarter of 2005 as compared to the third quarter of 2005 and also compared to the fourth quarter of 2004.

NETBACKS

(\$/boe)	Three months ended December 31		
	2005	2004	% change
Production revenue	64.71	42.62	52
Net royalties	(13.85)	(7.82)	77
Operating expenses	(7.64)	(7.60)	1
Transportation costs	(0.73)	(0.77)	(5)
Operating netback	42.49	26.43	61
General and administrative expenses	(1.85)	(1.58)	17
Interest expense	(0.24)	(0.76)	(68)
Current taxes	(0.50)	(0.33)	52
Cash flow netback (before abandonment)	39.90	23.76	68
Depletion, depreciation and accretion	(18.70)	(11.62)	61
Future income taxes	(4.27)	(4.18)	2
Stock-based compensation	(0.41)	(0.19)	116
Corporate netback (before abandonment)	16.52	7.77	113

Management's Evaluation of Disclosure Controls and Procedures

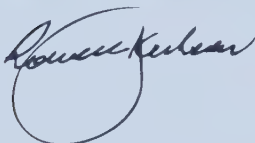
The Company maintains disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings, and other reports filed or submitted by it under provincial securities legislation is recorded, processed, summarized and reported within the time periods specified in the applicable securities legislation. The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the Company's disclosure controls and procedures as of March 14, 2006. Based on that evaluation these officers have concluded that the Company's disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Company in reports it files or submits under applicable securities legislation is recorded, processed, summarized and reported within the time periods as required and made known to them on a timely basis. The Company's disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives. The Chief Executive Officer and Chief Financial Officer do not expect that the disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control system are met.

CEO/CFO Certification

I, Lowell E. Jackson, President and Chief Executive Officer of Real Resources Inc. certify that:

- 1 I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 Certification of disclosure in Issuers' Annual and Interim Filings) of Real Resources Inc. (the "issuer") for the year ending December 31, 2005;
- 2 Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;
- 3 Based on my knowledge, the annual financial statements together with other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;
- 4 The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures and we have:
 - a. designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and
 - b. evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

March 14, 2006



Lowell E. Jackson, P. Eng
PRESIDENT AND CHIEF EXECUTIVE OFFICER

I, Pamela J. Orr, Vice President Finance and Chief Financial Officer of Real Resources Inc. certify that:

- 1 I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 Certification of disclosure in Issuers' Annual and Interim Filings) of Real Resources Inc. (the "issuer") for the year ending December 31, 2005;
- 2 Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;
- 3 Based on my knowledge, the annual financial statements together with other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;
- 4 The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures and we have:
 - a. designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and
 - b. evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

March 14, 2006



Pamela J. Orr, CA, CFA
VICE PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER

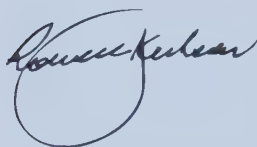
Management's Responsibility Statement

To the Shareholders of Real Resources Inc.

The accompanying consolidated financial statements and all other financial information presented in this annual report are the responsibility of Real's management. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

Management has developed and maintains systems of internal accounting controls, policies and procedures in order to provide for the safeguarding of assets and preparation of relevant, reliable and timely financial information.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. The Audit Committee reviews these statements with management and the auditors and reports to the Board of Directors who approve the financial statements.



LOWELL E. JACKSON, P. Eng.
PRESIDENT & CHIEF EXECUTIVE OFFICER



PAMELA J. ORR, CA, CFA
VICE PRESIDENT FINANCE & CHIEF FINANCIAL OFFICER

CALGARY, ALBERTA, CANADA
MARCH 14, 2006

Auditors' Report

To the Shareholders of Real Resources Inc.

We have audited the consolidated balance sheets of Real Resources Inc. as at December 31, 2005 and 2004 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all materials respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants

PricewaterhouseCoopers LLP

CALGARY, ALBERTA, CANADA

MARCH 14, 2006

Consolidated Balance Sheets

(\$ thousands)	December 31	
	2005	2004
ASSETS		
Current assets		
Accounts receivable	30,470	15,634
Prepaid expenses	1,770	1,129
	32,240	16,763
Property, plant and equipment (note 4)	497,441	262,893
	529,681	279,656
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	65,586	29,026
Long-term debt (note 5)	35,225	46,235
Asset retirement obligation (note 9)	17,896	13,635
Future income taxes (note 7)	88,890	46,766
Shareholders' equity		
Share capital (note 6)	219,763	91,767
Contributed surplus (note 10)	2,077	1,048
Retained earnings	100,244	51,179
	322,084	143,994
	529,681	279,656
Commitments (see note 8)		

See accompanying notes to the Consolidated Financial Statements



Robert B. Michaleski, CA
DIRECTOR



Frans Burger
DIRECTOR

Consolidated Statements of Operations and Retained Earnings

(\$ thousands, except per share amounts)	Years ended December 31	
	2005	2004
REVENUE		
Production revenue	215,271	108,103
Royalties	(41,360)	(23,067)
	173,911	85,036
EXPENSES		
Operating	27,502	20,019
Transportation costs	2,898	1,879
General and administrative	6,209	3,797
Stock-based compensation	1,437	446
Interest on long-term debt	1,776	2,141
Depletion, depreciation and accretion	58,609	30,269
	98,431	58,551
Earnings before taxes	75,480	26,485
TAXES (note 7)		
Future income taxes	24,659	9,543
Current	1,756	787
	26,415	10,330
NET EARNINGS	49,065	16,155
Retained earnings, beginning of year	51,179	36,205
Acquisition of shares in excess of assigned value (note 6(g))	-	(1,181)
RETAINED EARNINGS, END OF YEAR	100,244	51,179
Basic earnings per share (note 6(h))	\$ 1.44	\$ 0.60
Diluted earnings per share (note 6(h))	\$ 1.40	\$ 0.58

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

(\$ thousands)	Years ended December 31	
	2005	2004
CASH PROVIDED BY (USED IN):		
OPERATING ACTIVITIES		
Net earnings	49,065	16,155
Items not involving cash:		
Depletion, depreciation and accretion	58,609	30,269
Stock-based compensation	1,437	446
Future income taxes (note 7)	24,659	9,543
Abandonment expenditures	(355)	(240)
Cash flow from operations	133,415	56,173
Changes in non-cash working capital:		
Increase in trade and other receivables	(12,821)	(3,467)
Decrease (increase) in prepaid expenses	(604)	179
Increase in trade and other payables	7,975	3,122
	127,965	56,007
FINANCING ACTIVITIES		
Issue of common shares	95,030	47,337
Issue of share capital on exercise of stock options	2,243	1,089
Repurchase of shares (note 6(g))	-	(1,933)
Share issue costs	(5,431)	(3,156)
Decrease in long-term debt	(12,477)	(16,018)
	79,365	27,319
INVESTING ACTIVITIES		
Additions to capital assets	(200,701)	(90,620)
Corporate acquisition	(6,978)	-
Property acquisitions	(26,019)	-
Proceeds on property dispositions	78	309
	(233,620)	(90,311)
Changes in non-cash working capital:		
Increase in trade and other receivables	(86)	(2,291)
Increase in trade and other payables	26,376	9,276
	(207,330)	(83,326)
CHANGE IN CASH		
Cash, beginning of year	-	-
Cash, end of year	-	-
SUPPLEMENTARY DISCLOSURE		
Cash interest paid	1,844	2,099
Capital taxes paid	928	542

See accompanying notes to the Consolidated Financial Statements

Notes to the Consolidated Financial Statements

December 31, 2005 and 2004

(Tabular amounts in thousands of dollars, unless otherwise noted)

1. NATURE OF BUSINESS

Real Resources Inc. (Real or the Company) is a public company whose business is the exploration for and development of crude oil and natural gas in Western Canada. Real is incorporated under the Alberta Business Corporations Act and is listed on the Toronto Stock Exchange.

On April 8, 2005 the Company acquired all of the issued and outstanding shares of Freemont Exploration Corp. ("Freemont"), a private Alberta oil & gas exploration and development company (note 3). The assets of Freemont were subsequently contributed into Real Resources, the general partnership managed by the Company.

Effective January 1, 2006, Real and Freemont were amalgamated under the Alberta Business Corporations Act and will continue under the name Real Resources Inc.

2. ACCOUNTING POLICIES

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada. The preparation of the Consolidated Financial Statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenue and expenses during the reported period. Actual results may differ from these estimates.

(a) Principles of consolidation

The Consolidated Financial Statements include the accounts of the Company, its subsidiaries and its partnership.

(b) Joint operations

Significant portions of the Company's oil and gas activities are conducted jointly with others and accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

(c) Measurement uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the provision for asset retirement obligations are based on estimates. The cost-recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(d) Property, plant and equipment ("PP&E")

The Company follows the full-cost method of accounting for exploration and development expenditures. All costs of exploring, developing and acquiring petroleum and natural gas properties, including asset retirement costs, are capitalized and accumulated in one cost centre as all of the Company's operations are in Canada. Maintenance and repairs are charged against income and renewals and enhancements which extend the economic life of the PP&E are capitalized. Gains and losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20 percent or more.

(e) Depletion and depreciation

Depletion of petroleum and natural gas properties and depreciation of production equipment are calculated on the unit-of-production which is based on:

- (i) total estimated proved reserves calculated in accordance with National Instrument 51-101;
- (ii) total capitalized costs plus estimated future development costs of proved undeveloped reserves including discounted asset retirement costs, less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced; and
- (iii) relative volumes of petroleum and natural gas reserves and production before royalties, converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

(f) Impairment

The Company places a limit on the aggregate carrying value of PP&E.

Impairment is recognized if the carrying amount of the PP&E exceeds the sum of the undiscounted cash flows expected to result from the Company's proved reserves. Cash flows are calculated based on third-party quoted forward prices, adjusted for the Company's contract prices and quality differentials.

Upon recognition of impairment, the Company would then measure the amount of impairment by comparing the carrying amounts of the PP&E to the fair value of PP&E which is the estimated net present value of future cash flows from proved plus probable reserves. The Company's risk-free interest rate is used to arrive at the net present value of future cash flows. Any excess carrying value above the net present value of the Company's future cash flows would be recorded as a permanent impairment.

(g) Asset retirement obligation

The Company recognizes the fair value of its asset retirement obligation ("ARO") in the period in which it is incurred and when a reasonable estimate of fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Company's earnings in the period in which the settlement occurs.

(h) Derivative financial instruments

The Company may use various derivative financial instruments from time to time to manage its commodity price, foreign exchange and interest rate exposures. The Company does not use these instruments for trading purposes. The derivative financial instruments are initiated within the guidelines of the Company's risk management policy.

When it is deemed appropriate, the Company hedges its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars. These derivative contracts are not accounted for as hedges under Accounting Guideline 13 and are recorded at fair value on the Company's Consolidated Balance Sheet, with changes in fair value recorded in earnings. The Company may also enter into foreign exchange forward contracts to hedge anticipated U.S. dollar denominated petroleum and natural gas sales.

(i) Revenue recognition

Revenues from sales of petroleum and natural gas are recorded when title passes from the Company to external parties.

(j) Income taxes

The Company follows the liability method of accounting for income taxes. Under this method, the Company records future income taxes to account for the effect of any differences between the accounting and the income tax basis of an asset or liability using income tax rates substantively enacted at the Balance Sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in income in the period of the change.

(k) Stock-based compensation plan

The Company's Option Plan provides for granting of stock options to directors, officers and employees. The Company uses the fair value method for valuing stock option grants. Compensation costs attributed to share options granted are measured at fair value at the grant date and are expensed over the expected vesting time-frame with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the option holder together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(l) Per share information

Per share information is calculated on the basis of the weighted average number of common shares outstanding during the fiscal year. Diluted per share information reflects the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options would be used to buy back common shares at the average market price for the period.

(m) Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. A future tax liability is recognized upon the filing of the renunciation with the tax authorities and share capital is reduced by the estimated costs of the renounced tax deductions.

3. ACQUISITIONS

- (a) On April 8, 2005, the Company acquired all of the issued and outstanding shares of Freemont Exploration Corp. ("Freemont"), a private oil and gas company. The operating results and corresponding cash flow and earnings related to the acquisition were included in the Company's Consolidated Financial Statements effective April 9, 2005. The acquisition was accounted for by the purchase method and the purchase price was allocated based on fair values as follows:

Non-cash working capital	(244)
Property, plant and equipment	45,773
Long-term debt	(1,467)
Asset retirement obligation	(458)
Future income taxes	(13,709)
Total consideration	29,895
Consideration was comprised of:	
Issue of 1,636,907 common shares at \$14.00 per share	22,917
Cash paid to Freemont shareholders	6,500
Acquisition costs	478
Total consideration	29,895

- (b) Concurrent with this transaction, additional oil and gas assets in the same area ("additional assets") were acquired from multiple private companies. The consideration paid by the Company was an aggregate of 0.780 million common shares and \$3.9 million in cash for a deemed aggregate value of \$14.8 million.

4. PROPERTY, PLANT AND EQUIPMENT

	2005	2004
Oil and gas property, plant and equipment	672,271	379,362
Other	1,902	1,109
	674,173	380,471
Less: accumulated depletion and depreciation	176,732	117,578
	497,441	262,893

At December 31, 2005, oil and gas properties included \$59.1 million (2004: \$23.8 million) relating to unproved properties and unevaluated 3-D proprietary seismic which has been excluded from the depletion and depreciation calculation. Future development costs on proved undeveloped reserves of \$35.0 million (2004: \$15.1 million) are included in the depletion calculation.

Included in the Company's property, plant and equipment balance is \$9.6 million (\$7.1 million at December 31, 2004) net of accumulated depletion relating to the asset retirement obligation.

In 2005, the Company capitalized \$2.6 million (2004: \$1.9 million) of overhead directly related to exploration and development activities.

Real performs a ceiling test calculation at least annually in accordance with the Canadian Institute of Chartered Accountants' full cost accounting guidelines. No write-down was required for the year ended December 31, 2005 and December 31, 2004 based on expected realized future commodity prices.

Years ended December 31	Oil Price		Gas Price		NGL Price	
	2005	2004	2005	2004	2005	2004
2005	-	44.77	-	6.63	-	39.11
2006	62.16	42.51	10.35	6.34	54.63	36.59
2007	59.22	39.58	9.31	6.07	52.08	33.71
2008	56.33	36.69	8.12	5.80	49.60	30.80
2009	53.48	34.40	7.50	5.53	47.21	29.04
2010	50.69	34.86	6.88	5.64	44.41	29.58
Thereafter	53.99	39.51	8.12	6.75	49.11	32.62

5. LONG-TERM DEBT

At December 31, 2005, the Company had a financing commitment with three Canadian chartered banks which provided for a consolidated syndicated and operating facility of \$150 million and a US\$15 million swap facility. The credit facility revolves and fluctuates at the Company's option for a maximum of 364 days after the date of the banks' consent. If the revolving facility is not renewed at the end of the current revolving phase, the facility moves into the term phase whereby the credit facility will be permanently reduced by one payment on the 366th day following the last day of the revolving phase, which is the maturity date, in an amount equal to the outstanding principal.

The credit facility provides that advances may be made by way of direct advances, bankers' acceptances or U.S. dollar LIBOR advances which bear interest at prevailing bankers' acceptances or LIBOR rates plus an applicable bank fee per annum or bank's prime lending rate, depending on the nature of the advance. The authorized limit is subject to an annual review and re-determination of the Company's borrowing base by the bank.

Collateral pledged for the facility consists of a fixed and floating charge demand-debenture in the principal amount of \$250 million conveying a floating charge on all of the property and assets of the Company.

6. SHARE CAPITAL

(a) Authorized

Unlimited number of voting common shares without par value.

Unlimited number of first, second, third and fourth class preferred shares, issuable in series.

(b) Common shares issued

	2005		2004	
	Number of Shares (thousands)	Amount (\$ thousands)	Number of Shares (thousands)	Amount (\$ thousands)
Balance at beginning of year	29,090	91,767	23,351	52,693
Issue of common shares (c)	5,195	95,030	4,305	27,337
Flow-through share issue (d)	-	-	1,270	20,000
Future tax on flow-through issue (d)	-	-	-	(6,786)
Issuance of shares for corporate acquisition (e)	1,637	22,917	-	-
Issuance of shares for property acquisitions (e)	780	10,919	-	-
Issued for cash on exercise of stock options (f)	550	2,243	439	1,089
Repurchase of common shares (g)	-	-	(275)	(752)
Stock-based compensation	-	408	-	80
Share issue costs (net of tax effect)	-	(3,521)	-	(1,894)
Balance at end of year	37,252	219,763	29,090	91,767

(c) On March 30, 2004, the Company closed a common share equity offering for a total of 4.305 million common shares at a price of \$6.35 per share for total gross proceeds of \$27.3 million (\$25.6 million net of costs).

On March 1, 2005, the Company closed a common share equity offering of 2.527 million common shares at a price of \$13.85 per share for total gross proceeds of approximately \$35.0 million (\$32.9 million net of costs).

On August 24, 2005, the Company closed a common share equity offering of 2.668 million common shares at a price of \$22.50 per share for total gross proceeds of approximately \$60.0 million (\$56.8 million net of costs).

(d) On December 16, 2004, the Company closed a flow-through share equity offering for a total of 1.27 million common shares at a price of \$15.75 per share for total gross proceeds of \$20.0 million (\$18.7 million net of costs). Real committed to spending \$20.0 million in qualifying Canadian Exploration Expenditures pursuant to this flow-through share issue in December 2004. All of the expenditures were renounced effective December 31, 2004 and the expenditures were incurred prior to December 31, 2005.

(e) On April 8, 2005, the Company acquired all of the outstanding shares of a private company pursuant to an agreement dated April 8, 2005. At closing, Real issued 1.637 million common shares at a deemed value of approximately \$22.9 million (see note 3).

Concurrent with this transaction, and pursuant to agreements dated April 8, 2005, Real purchased additional interests in the same oil and gas assets from multiple other private companies. As consideration for the transaction, the multiple private companies received 0.780 million shares at a deemed value of approximately \$10.9 million and \$3.9 million in cash (see note 3).

(f) Stock-based compensation plan

The Company has a stock option plan that provides for the issuance of options to its directors, officers and employees to acquire up to 2.433 million common shares. The options typically vest evenly over a three-year period and expire five years from the date of grant. Compensation costs attributable to share options granted are measured at their fair value at the grant date and are expensed over the expected vesting time-frame with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the option holder together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

The stock-based compensation expense does not include compensation costs associated with stock options granted prior to January 1, 2002. The fair value of each option granted is estimated on the date of grant using the Black-Scholes options pricing model with the following weighted average assumptions:

	2005	2004
Fair value of options granted (\$/share)	4.76	1.46
Risk-free interest rate (%)	2.3	2.9
Expected life (years)	3.4	3.3
Expected volatility (%)	39	29
Expected dividend yield (%)	-	-

Stock option plan

A summary of the status of the Company's stock option plan as of December 31, 2005 and 2004, and changes during the years ended on those dates is presented below:

	2005		2004	
	Number of Options (thousands)	Weighted Average Exercise Price (\$/share)	Number of Options (thousands)	Weighted Average Exercise Price (\$/share)
Balance, beginning of year	1,932	4.85	1,942	3.77
Granted	1,152	17.18	475	7.11
Exercised	(550)	4.08	(439)	2.48
Expired/cancelled	(101)	11.41	(46)	5.23
Balance, end of year	2,433	10.59	1,932	4.85
Exercisable at end of year	827	4.60	845	3.90

The following table summarizes information regarding stock options outstanding at December 31, 2005:

Options Outstanding at December 31, 2005				Options Exercisable at December 31, 2005	
Range of Exercise Prices	Number Outstanding (thousands)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (\$/share)	Number Exercisable (thousands)	Weighted Average Exercise Price (\$/share)
\$3.01 - \$4.70	895	2.0	4.20	687	4.11
\$5.09 - \$9.45	439	3.4	7.06	140	6.98
\$13.08 - \$18.53	821	4.3	14.95	-	-
\$21.06 - \$26.15	278	4.8	23.91	-	-
	2,433	3.4	10.59	827	4.60

(g) Normal Course Issuer Bid

On June 17, 2004, the Company announced its intention to make a Normal Course Issuer Bid (the "Bid") through the facilities of the Toronto Stock Exchange to acquire for cancellation up to 1,391,000 common shares of the Company, which represented approximately five percent of the Company's issued and outstanding common shares. The Bid commenced on June 21, 2004 and terminated on June 20, 2005. During 2004 the Company purchased 55,100 common shares under this Bid for a total cost of \$450,000. The excess cost over book value of the shares purchased was applied to Retained Earnings. No shares were purchased in 2005.

On June 15, 2005, the Company announced its intention to make a Normal Course Issuer Bid (the "Bid") through the facilities of the Toronto Stock Exchange to acquire for cancellation up to 1,704,000 common shares of the Company, which represented approximately five percent of the Company's issued and outstanding common shares. The Bid commenced on June 21, 2005 and will terminate on June 20, 2006. As at December 31, 2005, the Company had not purchased any shares under this Bid.

(h) Per share amounts

The following table summarizes the basis for determining basic and diluted per share amounts:

	2005	2004
Weighted average shares outstanding (thousands)	34,031	26,932
Dilutive stock options outstanding (thousands)	2,156	1,917
Shares repurchased with proceeds from dilutive stock options and returned to treasury (thousands)	(1,017)	(1,125)
Weighted average diluted common shares outstanding (thousands)	35,170	27,724
Net earnings per common share		
Net earnings	49,065	16,155
Basic (\$/share)	1.44	0.60
Diluted (\$/share)	1.40	0.58

During 2005, 277,500 stock options were anti-dilutive and were omitted from the weighted average diluted common shares outstanding calculation (2004: 15,000).

7. TAXES

The difference between the expected income tax provision based on the combined federal and provincial statutory tax rate of 38.7 percent (2004: 39.3 percent) and the amount actually provided for is as follows:

	2005	2004
Expected future income taxes	29,226	10,382
Non-deductible Crown payment	3,999	4,801
Alberta Royalty Tax Credit	(124)	(125)
Resource allowance	(5,128)	(4,200)
Crown royalty adjustments	(1,152)	-
Rate reduction	-	(791)
Rate differential between current and future income taxes	(3,058)	(727)
Non-deductible stock-based compensation expense	556	175
Other	340	28
Total future income taxes	24,659	9,543
Capital taxes	1,756	787
Total taxes	26,415	10,330

The Company's future income tax liability as at December 31, 2005 is comprised of the following:

	2005	2004
Property, plant and equipment having different income tax and accounting basis	97,395	52,450
Asset retirement obligation	(6,205)	(4,615)
Share issuance costs	(2,300)	(1,069)
	88,890	46,766

8. COMMITMENTS

Real is committed to payments under operating leases for office space, gathering and transportation obligations, equipment leases and vehicles as follows:

2006	762
2007	574
2008	571
2009	930
2010	1,070
Thereafter	2,587
	6,494

9. ASSET RETIREMENT OBLIGATION

The total future asset retirement obligation was estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of its total asset retirement obligations to be \$17.9 million at December 31, 2005 based on a total future liability of \$33.3 million. These payments are expected to be made over the next 21 years with the majority of costs incurred between 2014 and 2018. The Company's credit adjusted risk-free rate of seven percent (2004: seven percent) and an inflation rate of two percent were used to calculate the net present value of the asset retirement obligation.

The following table reconciles the Company's total asset retirement obligation:

	2005	2004
Balance at January 1	13,635	11,807
Increase in liabilities	1,702	1,195
Increase in liabilities - corporate acquisition	458	-
Increase in liabilities - property acquisitions	1,485	-
Settlement of liabilities	(355)	(240)
Accretion expense	971	873
Balance at December 31	17,896	13,635

10. CONTRIBUTED SURPLUS

The following table reconciles the Company's contributed surplus:

	2005	2004
Balance at January 1	1,048	682
Stock-based compensation expense	1,437	446
Options exercised	(408)	(80)
Balance at December 31	2,077	1,048

11. FINANCIAL INSTRUMENTS

The Company's financial instruments recognized in the Consolidated Balance Sheets consist of accounts receivable, accounts payable, accrued assets and liabilities and long-term debt. The carrying value of these balances approximate their fair market value.

A substantial portion of the Company's accounts receivable are with customers and joint-venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's oil, gas and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact the Company's cash and cash equivalents that have a floating interest rate. The bank facility is also based on a floating interest rate. The Company had no interest rate swaps or hedges at December 31, 2005.

Eight Year History

FINANCIAL INFORMATION

(thousands, except per share amounts)

	Years ended December 31							
	2005	2004	2003	2002	2001	2000	1999	1998
Production revenue	215,271	108,103	73,282	52,554	51,527	39,526	15,816	9,872
Net earnings	49,065	16,155	14,597	5,907	7,607	8,582	4,569	(19,486)
Per share - basic	\$ 1.44	\$ 0.60	\$ 0.64	\$ 0.30	\$ 0.41	\$ 0.51	\$ 0.30	\$ (1.98)
Cash flow from operations	133,415	56,173	36,142	26,829	27,578	22,720	8,061	2,768
Per share - basic	\$ 3.92	\$ 2.09	\$ 1.58	\$ 1.36	\$ 1.48	\$ 1.35	\$ 0.54	\$ 0.28
Capital expenditures, net of dispositions (including business combinations)	269,167	90,311	59,499	54,270	34,710	55,196	9,070	19,754

Balance sheet information

Working capital (deficiency) surplus	(33,346)	(12,263)	(5,444)	(2,920)	(2,652)	(6,584)	(1,973)	568
Property, plant and equipment, net	497,441	262,893	200,783	153,656	113,242	90,048	30,118	24,926
Total assets	529,681	279,656	211,967	163,346	121,038	99,833	35,115	28,347
Long-term debt	35,225	46,235	62,253	53,650	30,037	22,725	3,789	8,998
Net debt	68,571	58,498	67,697	56,570	32,689	29,309	5,762	8,430
Shareholders' equity	322,084	143,994	89,580	61,624	53,787	42,120	23,118	16,067

SHARE INFORMATION

Common share outstanding (thousands) ⁽¹⁾	37,252	29,090	23,351	20,507	19,584	18,474	16,028	11,923
Weighted average shares outstanding (thousands)	34,031	26,932	22,804	19,716	18,593	16,803	15,033	9,853

Trading information ⁽¹⁾

Trading volume (thousands)	45,636	26,201	26,218	13,764	7,655	4,880	3,125	2,694
Share price (\$/share)								
High	\$ 27.99	\$ 13.55	\$ 5.70	\$ 5.10	\$ 4.80	\$ 4.00	\$ 2.68	\$ 5.60
Low	\$ 11.46	\$ 5.33	\$ 4.06	\$ 2.90	\$ 2.75	\$ 1.54	\$ 1.00	\$ 1.40
Close	\$ 24.90	\$ 11.84	\$ 5.50	\$ 5.10	\$ 3.20	\$ 3.30	\$ 1.68	\$ 1.60

OPERATING INFORMATION

Production ⁽²⁾

Crude oil and NGL (bbls/d)	5,152	3,293	3,352	3,248	2,603	2,160	1,665	1,608
Natural gas (mcf/d)	34,451	24,478	12,833	9,148	10,025	4,658	344	396
Total oil equivalent (boe/d)	10,394	7,373	5,491	4,772	4,274	2,937	1,722	1,674

	Years ended December 31							
	2005	2004	2003	2002	2001	2000	1999	1998
Reserves (proved) ⁽³⁾								
Crude oil and NGL (mbbls)	12,704	9,441	8,787	8,531	6,655	5,280	4,867	4,128
Natural gas (mmcf)	83,459	69,540	60,200	43,662	30,830	37,516	7,631	5,095
Total oil equivalent (mboe)	26,614	21,031	18,820	15,808	11,793	11,533	6,139	4,977
Reserves (proved plus probable) ⁽³⁾								
Crude oil and NGL (mbbls)	17,225	13,597	11,537	10,039	7,848	6,293	6,277	5,551
Natural gas (mmcf)	126,213	91,473	82,598	53,304	38,044	44,274	10,198	8,714
Total oil equivalent (mboe)	38,261	28,843	25,303	18,923	14,188	13,671	7,976	7,003
Reserve additions ⁽³⁾								
Proved	9,376	4,909	5,016	5,761	1,820	6,472	1,791	2,356
Proved plus probable	13,211	6,238	8,384	6,481	2,077	6,769	1,603	3,628
Finding costs per unit (/boe) ⁽³⁾								
Proved	\$ 25.10	\$ 14.10	\$ 9.19	\$ 8.01	\$ 14.80	\$ 7.95	\$ 4.25	\$ 7.23
Proved plus probable	\$ 17.82	\$ 11.10	\$ 5.50	\$ 7.12	\$ 12.97	\$ 7.61	\$ 4.75	\$ 4.70
On-stream cost per unit (/boe) ⁽³⁾								
Proved	\$ 28.71	\$ 18.39	\$ 11.86	\$ 9.42	\$ 19.07	\$ 8.52	\$ 5.05	\$ 8.31
Proved plus probable	\$ 20.37	\$ 14.48	\$ 7.10	\$ 7.54	\$ 14.87	\$ 8.14	\$ 5.65	\$ 5.40
Operating netback (/boe)	\$ 37.84	\$ 23.39	\$ 20.97	\$ 18.34	\$ 20.87	\$ 24.39	\$ 16.08	\$ 7.71
Recycle ratio								
Proved	1.32	1.27	1.77	1.95	1.09	2.86	3.18	0.93
Proved plus probable	1.86	1.62	2.95	2.19	1.25	2.99	2.85	1.43
Present value of future cash flow (in millions discounted at 15%)	537.7	271.4	167.2	161.0	99.0	121.2	54.6	42.2
Drilling activity (Gross wells drilled)	135	112	91	114	86	45	22	35
Net undeveloped land (thousands of acres)	407.9	306.9	239.9	191.9	172.9	155.9	98.1	96.5
Production (boe/d)								
Drilling	8,609	5,927	3,859	3,676	2,878	2,332	1,167	801
Acquisitions	1,785	1,446	1,632	1,096	1,396	605	555	873
	10,374	7,373	5,491	4,772	4,274	2,937	1,722	1,674
Production per share (boe per mm shares)	305	274	241	242	218	175	115	170
Reserves per share (proved plus probable) boe per thousand shares	1,124	1,071	1,110	960	763	740	532	710
3-D seismic (square miles)								
Proprietary	318	115	89	43	14	0	0	6
Trade	355	212	136	58	28	19	0	15

(1) On May 18, 2000 shareholders of the Company approved the consolidation of the common shares on the basis of one new common share being issued for every four previously issued and outstanding common shares.

(2) Where converted to a barrel of oil equivalent basis, all natural gas production results have been converted at the rate of six thousand cubic feet to one barrel of oil equivalent (boe).

(3) Reserves for 2002, 2001, 2000, 1999 and 1998 represent proved plus 50 percent risked probable reserves.

Real's strength lies in the quality of our dedicated staff.

Their commitment, enthusiasm and expertise are the foundations of the Company's future growth.

Caryn Allen
Leah Alspach
Cathy Anton
Shelley Ashbury
Randy Bartlett
Veda Burby
Erin Buschert
Terry Butterworth
Vim Cameron
Samantha Chan
Tom Charuk
Kristin Clark
Dale Collett
Robert Conrad
Silvana Corradetti
Robert Cruickshank
Dale Cugnet
Ted Cutts
Heather Dalton
Lee Davis
Sandy Denton
Anne Dunn
Dannielle DuPont

Connie Edlund
Jonny Evenson
Rhonda Fairbairn
Christa Giles
Wade Golby
Miriam Goodman
Larry Green
Amy Greggains
Pam Hay
Dennis Hodge
Dale Hoff
Jennifer Holben
Lee Hopkins
Lowell Jackson
Kevin Kelts
Mike Kolenosky
Bob Lagimodiere
Nathan Laviolette
Monty Low
Chris Madsen
Kent Manuel
Muriel McCallum
Natasha Michalezki

Doug Moore
Kevin Moore
Valerie Morrison
Frank Muller
Mary Murphy-Watch
Lyle Nakaska
Glenn Nevokshonoff
Sean Nicholson
Pamela Orr
Jennifer Perry
Dan Petch
Lori Peters
Tara Proctor
Joe Recsky
Pearl Redgate
Bob Riopel
Wes Roberts
Daryll Robinson
Deborah Rodtka
Kevin Roll
Michael Scase
Jennifer Scharnau
Michael Slezak

David Sloan
Brian Sondergaard
Geri Spring
Peter Stokes
Michael Stone
Kevin Taylor
Roy Taylor
Steve Thompson
Bob Torstensen
Rodger Trimble
Kahlil Trotman
Dean Tucker
Jim Twanow
Lisa Ulseth
Erik Vik
Craig Wall
Rob Wall
Larry Ward
Veera Wiber
Rodi Wiest
Zofia Wojcicka
Shyanne Woroniuk



Corporate Information

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DIRECTORS

Martin G. Abbott, LLB ^(1, 2)
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Frans Burger ^(1, 4, 5)
Dallas L. Droppo, Q.C. ^(3, 5)
Richard N. Edgar, P. Geol ⁽⁴⁾
Lowell E. Jackson, P. Eng. ^(3, 5)
Robert B. Michaleski, CA ^(1, 2)

OFFICERS

Lowell E. Jackson, P. Eng.
President & Chief Executive Officer

Pamela J. Orr, CA, CFA
Vice President Finance & Chief
Financial Officer

Frank P. Muller, P. Geol.
Vice President Exploration

Michael J. Stone
Vice President Land

Rodger D. Trimble, P. Eng.
Vice President Engineering

J. Dean Tucker, P. Eng.
Vice President Operations

Dallas L. Droppo, Q.C.
Secretary

COMMITTEES

Audit Committee ⁽¹⁾
Compensation Committee ⁽²⁾
Health, Safety &
Environmental Committee ⁽³⁾
Reserves Audit Committee ⁽⁴⁾
Risk Management Committee ⁽⁵⁾

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

BANKERS

Canadian Imperial Bank of Commerce
Calgary, Alberta

Bank of Montreal
Calgary, Alberta

The Bank of Nova Scotia
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Computershare Investor Services Inc.
Calgary, Alberta

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

RESERVE CONSULTANTS

Paddock, Lindstrom &
Associates Ltd.
Calgary, Alberta

STOCK EXCHANGE

Toronto Stock Exchange
Trading Symbol: RER

ABBREVIATIONS

bbls	barrels
mbbls	thousands of barrels
bbls/d	barrels of oil per day
mcf	thousand of cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	mmcf/d
bcf	billion cubic feet
boe	barrel of oil equivalent where natural gas is equat- ed to oil using 6 mcf = 1 barrel of oil
mboe	thousand barrels of oil equivalent
boe/d	barrel of oil equivalent per day
NGL	natural gas liquids
WTI	West Texas Intermediate

REAL 2005 TRADING SUMMARY

	Price Range (\$)			Trading Volume
	High	Low	Close	
1st Quarter	15.30	11.46	13.75	8,067,434
2nd Quarter	17.24	12.65	16.50	9,326,704
3rd Quarter	27.99	16.53	27.30	19,678,061
4th Quarter	27.70	21.25	24.90	8,563,748
				45,635,947



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